CONOCOPHILLIPS
Form 10-K
February 25, 2009

Table of Contents

2008

UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549
Form 10-K

(Mark One)

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

For the fiscal year ended December 31, 2008

OR

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

For the transition period from __________ to __________

Commission file number 001-32395

ConocoPhillips

(Exact name of registrant as specified in its charter)

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

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

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

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

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

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

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

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

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

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

Large accelerated filer þ Accelerated filer o Non-accelerated filer o Smaller reporting company o

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

The aggregate market value of common stock held by non-affiliates of the registrant on June 30, 2008, the last business day of the registrant s most recently completed second fiscal quarter, based on the closing price on that date of $94.39, was $143.4 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 741,761 and 42,397,731 shares, respectively, in determining the aggregate market value.

The registrant had 1,480,240,553 shares of common stock outstanding at January 31, 2009.

Documents incorporated by reference:

Portions of the Proxy Statement for the Annual Meeting of Stockholders to be held on May 13, 2009 (Part III)

TABLE OF CONTENTS

Table of Contents

PART I

Unless otherwise indicated, the company, we, our, us and ConocoPhillips are used in this report to refer to the businesses of ConocoPhillips and its consolidated subsidiaries. Items 1 and 2, Business and Properties, contain forward-looking statements including, without limitation, statements relating to our 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 forecast, intend, believe, expect, plan, schedule, target, should, goal, estimate and similar expressions identify forward-looking statements. The company does not undertake to update, revise or correct any 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 72.

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. and Phillips Petroleum Company. The merger between Conoco and Phillips was consummated on August 30, 2002.

Our business is organized into six operating segments:

- **Exploration and Production (E&P)** This segment primarily explores for, produces, transports 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, predominantly in the United States and Trinidad. The Midstream segment primarily consists of our 50 percent equity investment in DCP Midstream, 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, an international, integrated oil and gas company headquartered in Russia. At December 31, 2008, our ownership interest was 20 percent based on issued shares and 20.06 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.
- **Emerging Businesses** This segment represents our investment in new technologies or businesses outside our normal scope of operations.

At December 31, 2008, ConocoPhillips employed approximately 33,800 people.

SEGMENT AND GEOGRAPHIC INFORMATION

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

EXPLORATION AND PRODUCTION (E&P)

At December 31, 2008, our E&P segment represented 67 percent of ConocoPhillips total assets. This segment explores for, produces, transports 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 bitumen and upgrade it into a synthetic crude oil. Operations to liquefy natural gas and transport the resulting liquefied natural gas (LNG) are also included in the E&P segment. At December 31, 2008, our E&P operations were producing in the United States, Norway, the United Kingdom, Canada, Ecuador, Australia, offshore Timor-Leste in the Timor Sea, Indonesia, China, Vietnam, Libya, Nigeria, Algeria and Russia.

In October 2008, we closed on a transaction with Origin Energy to further enhance our long-term Australasian natural gas business. The 50/50 joint venture, named Australia Pacific LNG, will focus on coalbed methane production from the Bowen and Surat basins in Queensland, Australia, and LNG processing and export sales.

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 our LUKOIL Investment segment. As a result, references to results, production, prices and other statistics throughout the E&P segment discussion exclude amounts related to our investment in LUKOIL. However, our share of LUKOIL is included in the supplemental oil and gas operations disclosures on pages 147 through 166, as well as in the net proved reserves table shown below.

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 (BOE).
- Net wells completed, wells in progress and productive wells.
- Developed and undeveloped acreage.

The following table is a summary of the proved reserves information included in the supplemental oil and gas operations disclosures. Natural gas reserves are converted to BOE based on a 6:1 ratio: six thousand cubic feet of natural gas converts to one BOE.

	Millions of Barrels of Oil Equivalent			
Net Proved Reserves at December 31	**2008**	2007	2006	2005
Crude oil				
Consolidated	**2,723**	3,104	3,200	3,336
Equity affiliates	**2,317**	2,398	2,690	2,430
Total Crude Oil	**5,040**	5,502	5,890	5,766
Natural gas				
Consolidated	**3,360**	3,750	3,908	2,752
Equity affiliates	**798**	490	565	425
Total Natural Gas	**4,158**	4,240	4,473	3,177
Natural gas liquids				
Consolidated	**717**	759	774	402
Equity affiliates	**60**	59	32	21
Total Natural Gas Liquids	**777**	818	806	423

Total consolidated	**6,800**	7,613	7,882	6,490
Total equity affiliates	**3,175**	2,947	3,287	2,876
Total	**9,975**	10,560	11,169	9,366
Includes amounts related to LUKOIL investment:	***1,893***	*1,838*	*1,805*	*1,442*
Excludes Syncrude mining-related reserves:	***249***	*221*	*243*	*251*

Table of Contents

In 2008, E&P s worldwide production, including its share of equity affiliates production other than LUKOIL, averaged 1,767,000 barrels of oil equivalent per day (BOED), compared with the 1,857,000 averaged in 2007. During 2008, 775,000 BOED were produced in the United States, a decrease from 843,000 in 2007. Production from our international E&P operations averaged 992,000 BOED in 2008, a decrease compared with 1,014,000 in 2007. In addition, our Canadian Syncrude mining operations had net production of 22,000 barrels per day in 2008, compared with 23,000 in 2007. The change in worldwide production was primarily due to field decline and the expropriation of our Venezuelan oil interests, partially offset by production from new developments primarily in the United Kingdom, Indonesia, Russia, Norway and Canada.

E&P s worldwide annual average crude oil sales price increased 39 percent, from $67.11 per barrel in 2007 to $93.12 in 2008. E&P s average annual worldwide natural gas sales price increased 32 percent, from $6.26 per thousand cubic feet in 2007 to $8.27 in 2008.

E&P UNITED STATES

In 2008, U.S. E&P operations contributed 44 percent of E&P s worldwide liquids production and 43 percent of natural gas production, compared with 46 percent and 45 percent in 2007, respectively.

Alaska

Greater Prudhoe Area

The Greater Prudhoe Area is composed of the Prudhoe Bay field and five satellite fields, as well as the Greater Point McIntyre Area fields. Prudhoe Bay, the largest oil field on Alaska s North Slope, 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. Prudhoe Bay s satellites include Aurora, Borealis, Polaris, Midnight Sun and Orion, while the Point McIntyre, Niakuk, Raven and Lisburne fields are part of the Greater Point McIntyre Area. We have a 36.1 percent nonoperator interest in all fields within the Greater Prudhoe Area. Net oil production from the Greater Prudhoe Area averaged 106,000 barrels per day in 2008, compared with 107,000 in 2007, while natural gas liquids production averaged 17,000 barrels per day in 2008, compared with 19,000 in 2007.

Greater Kuparuk Area

We operate the Greater Kuparuk Area, composed of the Kuparuk field and four satellite fields: Tarn, Tabasco, Meltwater and West Sak. Kuparuk is located about 40 miles west of Prudhoe Bay. Our ownership interest in the area is approximately 55 percent. 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. Net oil production from the area averaged 67,000 barrels per day in 2008, compared with 74,000 in 2007.

Western North Slope

The Alpine field and its satellite fields, located west of the Kuparuk field, produced at a net rate of 70,000 barrels of oil per day in 2008, compared with 80,000 in 2007. We operate and hold a 78 percent interest in Alpine and its three satellites, the Nanuq, Fiord and Qannik fields. The Qannik field began production in July 2008.

Cook Inlet Area

Our assets include the North Cook Inlet field, the Beluga River field, and the Kenai LNG facility, all of which we operate. We have a 100 percent interest in the North Cook Inlet field, while we own 33.3 percent of the Beluga River field. Net production in 2008 from the Cook Inlet Area averaged 88 million cubic feet per day of natural gas, compared with 101 million in 2007. Production from the North Cook Inlet field is used primarily to supply our share of gas to the Kenai LNG plant and also as a backup supply to local utilities, while gas from the Beluga River field is primarily sold to local utilities and is used as backup 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. We sold 27 net billion cubic feet in 2008, compared with 31 billion in 2007. In June 2008, the U.S.

Department of Energy announced its approval of a two-year extension of the plant s export license, extending it through March 2011.

Exploration

We were the successful bidder on 98 blocks totaling $506 million in the February 2008 Chukchi Sea lease sale. During 2008, our primary area of exploratory drilling activity was in the National Petroleum Reserve-Alaska on the Western North Slope. Three wells were drilled in the area, and all three encountered hydrocarbons. One of the wells was expensed as a dry hole, and we are evaluating the potential for future development of the other two discoveries.

Transportation

We transport the petroleum liquids produced on the North Slope to south-central Alaska through an 800-mile pipeline that is part of the Trans-Alaska Pipeline System (TAPS). We have a 28.3 percent ownership interest in TAPS, and 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 North Slope production, using five company-owned double-hulled tankers in addition to chartering third-party vessels as necessary.

During the second quarter of 2008, ConocoPhillips and BP plc formed a limited liability company to progress the pipeline project named Denali The Alaska Gas Pipeline. The project, which would move approximately 4 billion cubic feet per day of Alaska natural gas to North American markets, would consist of a gas treatment plant on Alaska s North Slope and a large-diameter pipeline through Alaska to Alberta, Canada. Should a new pipeline be required to transport gas from Alberta, the project also could include a large-diameter pipeline from Alberta to the U.S. Lower 48. Denali announced plans to reach the first major project milestone before year-end 2010. This milestone is an open season, a process during which the pipeline company seeks customers to make long-term firm transportation commitments to the project. We expect Denali would seek certification from the Federal Energy Regulatory Commission (FERC) and the Canadian National Energy Board if the open season is successful, and thereafter move forward with project construction. Summer fieldwork related to the project began in late May 2008, primarily in eastern Alaska, and involved route reconnaissance and environmental studies. In late June 2008, the Denali project was approved to use FERC s prefiling process. There is a pipeline project competing with Denali that is structured under the Alaska Gasline Inducement Act.

U.S. Lower 48

Gulf of Mexico

At year-end 2008, our portfolio of producing properties in the Gulf of Mexico mainly consisted of one operated field and three fields operated by co-venturers, including:

- 75 percent operator interest in the Magnolia field in Garden Banks Blocks 783 and 784.
- 16 percent nonoperator interest in the unitized Ursa field located in the Mississippi Canyon area.
- 16 percent nonoperator interest in the Princess field, a northern, subsalt extension of the Ursa field.
- 12.4 percent nonoperator interest in the unitized K2 field, comprised of seven blocks in the Green Canyon area.

Net production from our Gulf of Mexico properties averaged 18,000 barrels per day of liquids and 24 million cubic feet per day of natural gas in 2008, compared with 25,000 barrels per day and 36 million cubic feet per day in 2007.

Onshore

Our 2008 onshore production principally consisted of natural gas, with the majority of production located in the San Juan Basin, Permian Basin, Lobo Trend, Bossier Trend, and panhandles of Texas and Oklahoma. We also have operations in the Wind River, Anadarko and Fort Worth basins, as well as in East Texas and northern and southern Louisiana. Other onshore ownership includes properties in the Williston Basin, the Piceance Basin and the Cedar Creek Anticline.

The San Juan Basin, located in northwestern New Mexico and southwestern Colorado, includes the majority of our coalbed methane (CBM) production. Additionally, we continue to pursue development opportunities in three conventional formations in the San Juan Basin. Net production from San Juan averaged 48,000 barrels per day of liquids and 863 million cubic feet per day of natural gas in 2008, compared with 50,000 barrels per day and 971 million cubic feet per day in 2007.

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

Onshore activities in 2008 were mostly centered on continued optimization and development of existing assets. Combined production from all Lower 48 onshore fields in 2008 averaged a net 1,970 million cubic feet per day of natural gas and 147,000 barrels per day of liquids, compared with 2,146 million cubic feet per day and 157,000 barrels per day in 2007.

Transportation

In 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 is completing construction of a 1,679-mile natural gas pipeline from Colorado to Ohio that is expected to have an approximate capacity of 1.8 billion cubic feet per day. A section of the pipeline extending from Colorado to Missouri was placed in service in May 2008, and construction continues on the remaining portion of the pipeline project. Full pipeline service extending to Lebanon, Ohio, is expected by June 2009, while service to the final destination of Clarington, Ohio, is scheduled to begin by year-end 2009.

Exploration

During 2008, we completed 122 gross onshore exploration wells. Most of the wells were located in the Bakken play in the Williston Basin, the Bossier Trend, and the Fort Worth Basin Barnett play, all of which are company focus areas. Other areas with active exploration drilling programs included the Anadarko Basin, Wyoming, Colorado and South Texas.

Gulf of Mexico deepwater leasehold acreage was expanded by successful bidding at federal offshore lease sales in March and August 2008, with high bids totaling $334 million, adding 22 new blocks. At year end we had interests in 267 lease blocks totaling 1.1 million net acres. During 2008, we completed two successful appraisal wells and participated in four deepwater exploration wells. Three of the exploration wells were expensed as dry holes, and operations on one well continued into 2009.

E&P EUROPE

In 2008, E&P operations in Europe contributed 24 percent of E&P s worldwide liquids production, compared with 22 percent in 2007. European operations contributed 20 percent of natural gas production in 2008, compared with 19 percent in 2007. Our European assets are principally located in the Norwegian and U.K. sectors of the North Sea.

Norway

We operate and hold a 35.1 percent interest in the Greater Ekofisk Area, located approximately 200 miles offshore Norway in the center of the North Sea. The Greater Ekofisk Area is composed of four producing fields: Ekofisk, Eldfisk, Embla and Tor. Net production in 2008 from the Greater Ekofisk Area was 99,000 barrels of liquids per day and 100 million cubic feet of natural gas per day, compared with 103,000 barrels per day and 103 million cubic feet per day in 2007.

Table of Contents

We also have varying ownership interests in other producing fields in the Norwegian sector of the North Sea and in the Norwegian Sea, including:

- 24.3 percent interest in the Heidrun field.
- 20 percent interest in the Alvheim field.
- 10.3 percent interest in the Statfjord field.
- 23.3 percent interest in the Huldra field.
- 1.6 percent interest in the Troll field.
- 9.1 percent interest in the Visund field.
- 6.4 percent interest in the Grane field.
- 2.4 percent interest in the Oseberg area.

Net production from these and other fields in the Norwegian sector of the North Sea and the Norwegian Sea averaged 68,000 barrels of liquids per day and 139 million cubic feet of natural gas per day in 2008, compared with 67,000 barrels per day and 133 million cubic feet per day in 2007.

The Alvheim North Sea development achieved first production in June 2008 through a floating production, storage and offloading (FPSO) vessel and subsea installations. At year-end 2008, Alvheim was producing at a net rate of 16,000 barrels per day of liquids and 7 million cubic feet per day of natural gas. Net peak production of 18,000 barrels per day of liquids and 9 million cubic feet per day of natural gas is expected in the second quarter of 2009.

Transportation

We have interests in the transportation and processing infrastructure in the Norwegian sector of the North Sea, including interests in the Norpipe Oil Pipeline System and in Gassled, which owns most of the Norwegian gas transportation system.

Exploration

We participated in seven exploration wells during 2008, with five of the wells encountering hydrocarbons. Two gas discoveries were made in the PL218 license, and two others were made in the Oseberg area. A discovery was also made on the East Flank of the Visund field, and operations in this well continued into 2009. In late 2008, we were awarded two Norway exploration licenses, both in the central North Sea.

United Kingdom

In addition to our 58.7 percent interest in the Britannia natural gas and condensate field, we own 50 percent of Britannia Operator Limited, the operator of the field. Net production from Britannia and its satellite fields averaged 277 million cubic feet of natural gas per day and 24,000 barrels of liquids per day in 2008, compared with 252 million cubic feet per day and 10,000 barrels per day in 2007. We achieved first production from two Britannia satellites, Callanish and Brodgar, in June and July 2008, respectively. We have a respective 83.5 percent interest and a 75 percent interest in these satellite fields.

We operate and hold a 36.5 percent interest in the Judy/Joanne fields, which together make up J-Block. Additionally, our operated Jade field, in which we hold a 32.5 percent interest, produces from a wellhead platform and pipeline tied to J-Block facilities. Together, these fields produced a net 13,000 barrels of liquids per day and 88 million cubic feet of natural gas per day in 2008, compared with 14,000 barrels per day and 94 million cubic feet per day in 2007.

Our various ownership interests in 18 producing gas fields in the Rotliegendes and Carboniferous areas of the southern North Sea yielded average net production in 2008 of 241 million cubic feet per day of natural gas, compared with 276 million in 2007.

Table of Contents

We also have ownership interests in several other producing fields in the U.K. sector of the North Sea, including:

- 23.4 percent interest in the Alba field.
- 40 percent interest in the MacCulloch field.
- 4.8 percent interest in the Statfjord field.

Production from these and other remaining fields in the U.K. sector of the North Sea averaged a net 17,000 barrels of liquids per day and 14 million cubic feet of natural gas per day in 2008, compared with 20,000 barrels per day and 15 million cubic feet per day in 2007.

In the Atlantic Margin, we have a 24 percent interest in the Clair field. Net production in 2008 averaged 11,000 barrels of liquids per day, compared with 7,000 in 2007.

The Millom, Dalton and Calder fields in the East Irish Sea, in which we have a 100 percent ownership interest, are operated on our behalf by a third party. Net production in 2008 averaged 43 million cubic feet of natural gas per day, compared with 36 million in 2007.

Transportation

The Interconnector pipeline, linking the United Kingdom and Belgium, facilitates marketing natural gas produced in the United Kingdom throughout Europe. Our 10 percent equity share allows us to ship approximately 200 million cubic feet of natural gas per day to markets in continental Europe, and our reverse-flow rights provide an 85 million cubic feet per day import capability into the United Kingdom.

We operate the Teesside oil and Theddlethorpe gas terminals, in which we have 29.3 percent and 50 percent ownerships, respectively. We also have a 100 percent ownership interest in the Rivers Gas Terminal, operated by a third party, in the United Kingdom.

Exploration

During 2008 we were awarded interests in three exploration licenses: two in the central North Sea and one in the West of Shetland region. We also participated in three appraisal wells and three exploration wells in the Southern Gas Basin, central North Sea and the West of Shetland region, with four of the wells encountering hydrocarbons. Three of these six wells were drilled in the proximity of the Jasmine discovery and confirmed the viability of that project.

Netherlands

Our varying nonoperator production interests in the Dutch sector of the North Sea, as well as interests in offshore pipelines and an onshore gas plant and terminal at Den Helder, were sold in December 2008. Net production in 2008 averaged 50 million cubic feet of natural gas per day, compared with 52 million in 2007.

E&P CANADA

In 2008, E&P operations in Canada contributed 8 percent of E&P s worldwide liquids production (excluding Syncrude production), compared with 7 percent in 2007. Canadian operations contributed 22 percent of E&P s worldwide natural gas production in 2008 and 2007.

Oil and Gas Operations

Western Canada

Operations in western Canada encompass properties throughout Alberta, northeastern British Columbia, and southern Saskatchewan. Net production from these oil and gas operations in western Canada averaged 44,000 barrels per day of liquids and 1,054 million cubic feet per day of natural gas in 2008, compared with 46,000 barrels per day and 1,106 million cubic feet per day in 2007.

Table of Contents

Surmont

We operate and have a 50 percent interest in the Surmont oil sands lease, located approximately 35 miles south of Fort McMurray, Alberta. The Surmont project uses an enhanced thermal oil recovery method called steam-assisted gravity drainage (SAGD). Steam injection began in the second quarter of 2007, and first production was achieved in the fourth quarter of 2007. Average net production of bitumen from Surmont during 2008 was 6,000 barrels per day, and the 2008 average sales price was $46.85 per barrel. Net peak production of 13,000 barrels per day is expected in 2013.

FCCL

On January 3, 2007, we closed on a business venture with EnCana Corporation to create an integrated North American heavy oil business. The venture consists of two 50/50 business ventures: a Canadian upstream general partnership, the FCCL Oil Sands Partnership, and a U.S. downstream limited liability company, WRB Refining LLC. FCCL 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 northeastern Alberta. EnCana is the operator and managing partner of FCCL. With Christina Lake phase 1B becoming operational in mid-2008 and the continuing ramp-up of Foster Creek phase C, our share of FCCL s production increased to 30,000 barrels per day in 2008, compared with 27,000 in 2007. Foster Creek phases D and E are expected to add additional production of more than 20,000 net barrels per day combined and are expected to become operational in early 2009. The average sales price realized on FCCL s 2008 production was $58.54 per barrel. See the Refining and Marketing (R&M) section for information on WRB.

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. 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. The Joint Review Panel (JRP), an independent body appointed by the Minister of Environment to evaluate the potential impacts of the project on the environment and lives of the people in the project area, completed public hearings in November 2007. The JRP issued a press release in December 2008, indicating a report assessing the environmental and socio-economic impact of the proposed project would be released in December 2009. The pipeline project awaits the JRP report and will continue to progress toward regulatory authorizations, but it has deferred detailed engineering work pending resolution with the federal government on the fiscal and commercial framework.

Exploration

We hold exploration acreage in four areas of Canada: western Canada, offshore eastern Canada, the Mackenzie Delta/Beaufort Sea region, and the Arctic Islands. In 2008, the company added 62,000 acres in the Horn River play in western Canada and acquired two additional Beaufort licenses. Within western Canada, we participated in 43 exploratory wells.

Syncrude Canada Ltd.

We own a 9 percent interest in the Syncrude Canada Ltd. (SCL) joint venture, created 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. SCL, as operator of the joint venture, holds eight oil sands leases and the associated surface rights, of which our share is approximately 22,400 net acres. Net production averaged 22,000 barrels per day in 2008, compared with 23,000 in 2007.

U.S. Securities and Exchange Commission regulations currently in effect define the Syncrude 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.

Table of Contents

E&P SOUTH AMERICA

In 2008, E&P operations in South America contributed 1 percent of E&P s worldwide liquids production, compared with 5 percent in 2007.

Venezuela

Petrozuata, Hamaca and Corocoro

On June 26, 2007, we announced we had been unable to reach agreement with respect to our migration to an *empresa mixta* structure mandated by the Venezuelan government s Nationalization Decree. In response, Venezuela s national oil company, Petróleos de Venezuela S.A. (PDVSA), or its affiliates directly assumed the activities associated with and control over ConocoPhillips interests in the Petrozuata and Hamaca heavy oil ventures and the offshore Corocoro development project.

Plataforma Deltana Block 2

We have a 40 percent nonoperated interest in Plataforma Deltana Block 2 which holds a gas discovery made by PDVSA. Several critical components required to progress an investment decision have not yet been defined by the govenment.

Peru

At year-end 2008, we held ownership interests in five exploration blocks in Peru. Two 2D seismic programs were carried out during the year in Blocks 39 and 104, and the sale of Block 57 was completed in the second quarter of the year. In the fourth quarter of 2008, we completed an appraisal well in Block 39, but the well did not confirm a stand-alone commercial hydrocarbon accumulation. The appraisal well and suspended discovery well were expensed as dry holes.

Ecuador

In Ecuador, we own a 42.5 percent interest in Block 7 and a 46.3 percent interest in Block 21. Net production in 2008 averaged 9,000 barrels of crude oil per day, compared with 10,000 in 2007.

Argentina

We sold our assets in Argentina in September 2008.

E&P ASIA PACIFIC

In 2008, E&P operations in the Asia Pacific region contributed 11 percent of E&P s worldwide liquids production and 13 percent of natural gas production, compared with 10 percent and 11 percent in 2007, respectively.

Australia and Timor Sea

Australia Pacific LNG

In October 2008, we closed on a transaction with Origin Energy, an integrated Australian energy company, to further enhance our long-term Australasian natural gas business. The 50/50 joint venture, named Australia Pacific LNG, will focus on coalbed methane (CBM) production from the Bowen and Surat basins in Queensland, Australia, and LNG processing and export sales. With this transaction, we gained access to CBM resources in Australia and will enhance our LNG position with the expected creation of an additional LNG hub targeting Asia Pacific markets. Four LNG trains are anticipated, each currently expected to process an estimated 3.5 million gross tons of LNG per year. An estimated 20,500 gross wells are ultimately envisioned to supply both the domestic gas market and the LNG development. Drilling and production operations will be supported by gas gathering systems and centralized gas processing and compression stations, as well as by dewatering and water treatment facilities.

Our share of the joint venture s year-end production rate was 68 million cubic feet per day. Current production is sold into the Australian domestic market. CBM field development work is ongoing in parallel with front-end engineering associated with the planned LNG processing facilities.

Table of Contents

Bayu-Undan

We operate and hold a 57.2 percent ownership interest in the Bayu-Undan field located in the Timor Sea. The field averaged a net production rate of 36,000 barrels of liquids per day in 2008, compared with 34,000 in 2007. Our share of natural gas production was 210 million cubic feet per day in 2008, compared with 189 million in 2007. Produced natural gas is used to supply the Darwin LNG plant, of which we own a 57.2 percent interest. In 2008, we sold 159 billion gross cubic feet of LNG to utility customers in Japan, compared with 140 billion in 2007.

Greater Sunrise

We have a 30 percent interest in the Greater Sunrise gas and condensate field located in the Timor Sea. Although agreement has been reached between the governments of Australia and Timor-Leste concerning sharing of revenues from the anticipated development of Greater Sunrise, key challenges to be resolved before significant funding commitments can be made include ensuring the reservoir is adequately appraised, gaining co-venturer and government alignment on the development concept, and establishing fiscal stability arrangements. Immediate activity is focused on reprocessing seismic data and integrating the results of an appraisal well to define the remaining appraisal program, as well as advancing the development concept screening phase.

Western Australia

In 2008, our share of production from the Athena/Perseus (WA-17-L) gas field, located offshore Western Australia, was 35 million cubic feet of natural gas per day, compared with 34 million in 2007.

Exploration

In November 2008, we acquired 50 percent interests in two permits in the Arafura Basin, offshore Northern Territory. In the Bonaparte Basin, we drilled one successful appraisal well at the Sunrise field. Additionally, seismic processing from the NT/P69 and the NT/P61 permits was completed, and interpretation of this data is currently under way to further evaluate the Caldita and Barossa discoveries.

The company also operates the WA-314-P, WA-315-P and WA-398-P permits in the Browse Basin. During 2008, acquisition and processing of seismic data in WA-398-P was completed. An exploration drilling campaign will be conducted in these permits during 2009.

Indonesia

We operate seven production sharing contracts (PSCs) in Indonesia. Production from Indonesia in 2008 averaged a net 343 million cubic feet per day of natural gas and 15,000 barrels per day of oil, compared with 330 million cubic feet per day and 12,000 barrels per day in 2007. Our assets are concentrated in two core areas: the West Natuna Sea and onshore South Sumatra.

We operate four offshore PSCs: South Natuna Sea Block B, Amborip VI, Kuma and Arafura Sea. The South Natuna Sea Block B PSC, in which we have a 40 percent interest, has two producing oil fields and 16 gas fields in various stages of development.

We operate three onshore PSCs. Corridor and South Jambi B are in South Sumatra, and Warim is in Papua. As part of the Corridor PSC, in which 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, Batam and West Java. We have a 45 percent interest in the South Jambi B PSC, a shallow gas project that supplies natural gas to Singapore.

Transportation

We are a 35 percent owner of a consortium company that has a 40 percent ownership in PT Transportasi Gas Indonesia, which owns and operates the Grissik to Duri and Grissik to Singapore natural gas pipelines.

Exploration

In November 2008, we acquired the Arafura Sea Block, and a 2D seismic survey was completed on the block by year end. One appraisal well was drilled at the South Belut field, and one appraisal well and one exploration well were drilled at the North Belut field.

Table of Contents

China

Production related to our 49 percent share of the Peng Lai 19-3 field in Bohai Bay Block 11-05 averaged 14,000 barrels of oil per day in 2008, compared with 10,000 in 2007. We also hold a 49 percent interest in the nearby Peng Lai 25-6 field. An FPSO vessel to accommodate production from both fields is expected to be installed in early 2009. Concurrent development of both fields continues.

The Xijiang development consists of two fields located approximately 80 miles south of Hong Kong in the South China Sea. Our ownership in these fields ranges from 12.3 percent to 24.5 percent. Facilities include two manned platforms and an FPSO vessel. Combined net production of oil from the Xijiang fields averaged 7,000 barrels per day in 2008, compared with 8,000 in 2007.

We have a 24.5 percent interest in the offshore Panyu field, also located in the South China Sea, which produced 12,000 net barrels of oil per day in 2008 and 13,000 in 2007. In July 2008, we sold our 100 percent interest in the onshore Ba Jiao Chang natural gas field.

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, four 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 2008 was 13,000 barrels of oil per day, compared with 14,000 in 2007. The oil is processed through a 1-million-barrel FPSO vessel and through the Su Tu Vang central processing platform and new floating storage and offloading (FSO) vessel. First oil production from the Su Tu Vang satellite field was achieved in October 2008.

Also in the Cuu Long Basin, we have a 36 percent interest in the Rang Dong field in Block 15-2. All wellhead platforms produce into an FSO vessel. Net production in 2008 was 9,000 barrels per day of liquids and 16 million cubic feet per day of natural gas, compared with 8,000 barrels per day and 15 million cubic feet per day in 2007.

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

In 2008, we drilled one exploration well in Block 15-1 that was expensed as a dry hole.

Malaysia

We have interests in three deepwater PSCs located off the eastern Malaysian state of Sabah: Block G, Block J, and the Kebabangan Cluster. Development of the Gumusut discovery in Block J continues.

Exploration

In 2008, we completed two successful appraisal wells in Block G to evaluate the prior Ubah and Petai discoveries. Kebabangan and Malikai, a Block G discovery, are moving toward field development.

E&P MIDDLE EAST AND AFRICA

During 2008, E&P operations in the Middle East and Africa contributed 8 percent of E&P s worldwide liquids production and 2 percent of natural gas production, the same as in 2007.

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. The project also includes a 7.8-million-gross-ton-per-year LNG facility, from which LNG will be shipped in

Table of Contents

new LNG carriers destined for sale in the United States and other markets. The first LNG cargoes are expected to be loaded in the fourth quarter of 2010.

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 from the LNG plant and associated facilities will be combined and shared.

We have a 12.4 percent ownership interest in the Golden Pass LNG regasification facility and associated pipeline. The facilities are currently being constructed on the Sabine-Neches Industrial Ship Channel northwest of Sabine Pass, Texas. Subject to the negotiation of definitive agreements, ConocoPhillips will also secure capacity rights in the regasification terminal and pipeline to manage the LNG we will purchase from Qatargas 3. In addition to the United States, other market alternatives for Qatargas 3 LNG production are being pursued. Despite sustaining some damage during Hurricane Ike, the Golden Pass LNG terminal is expected to be operational in time to receive the first cargoes of Qatargas 3 production.

Libya

ConocoPhillips holds a 16.3 percent interest in the Waha concessions in Libya, which encompass nearly 13 million gross acres. Net oil production averaged 47,000 barrels per day in 2008 and 2007.

Nigeria

During 2008, we produced from four onshore Oil Mining Leases (OMLs), in which we have a 20 percent nonoperator interest. Net production from these leases was 21,000 barrels of liquids per day and 105 million cubic feet of natural gas per day in 2008, compared with 19,000 barrels per day and 117 million cubic feet per day in 2007.

We have a 20 percent interest in a 480-megawatt gas-fired power plant in Kwale, Nigeria, which supplies electricity to Nigeria s national electricity supplier. In 2008, the plant consumed 11 million net cubic feet per day of natural gas sourced from our proved reserves in the OMLs.

We have a 17 percent equity interest in Brass LNG Limited, which plans to construct an LNG facility in the Niger Delta.

Exploration

We drilled an exploration well in block OPL214 that did not confirm commercial quantities of hydrocarbons and was expensed as a dry hole. Development planning activities for the prior Uge discovery in the same block continue. In the fourth quarter of 2007, we assigned our interest in OPL248 to a co-venturer. This assignment was formally acknowledged by the Nigerian government in the third quarter of 2008.

Abu Dhabi

In July 2008, we signed an Interim Agreement with the Abu Dhabi National Oil Company (ADNOC) to develop the Shah gas field in Abu Dhabi. This large-scale project involves the development of natural gas condensate reservoirs within the onshore Shah gas field, the construction of a new 1-billion-cubic-feet-per-day natural gas processing plant at Shah, new natural gas and liquid pipelines, and sulfur-exporting facilities at Ruwais. ADNOC would have a 60 percent interest and we would have a 40 percent interest in the project. We are currently working on final project agreements with ADNOC.

Algeria

We have interests in three fields in Block 405a: the Menzel Lejmat North field, the Ourhoud field, and the development stage El Merk (EMK) oil field unit. Net production from these fields averaged 13,000 barrels of oil per day in 2008, compared with 11,000 in 2007.

Table of Contents

E&P RUSSIA AND CASPIAN

Russia

Polar Lights

We have a 50 percent equity interest in Polar Lights Company, an entity created to develop fields in the Timan-Pechora Basin in northern Russia. Net production averaged 11,000 barrels of oil per day in 2008, compared with 12,000 in 2007.

NMNG

We have a 30 percent ownership interest with a 50 percent governance interest in OOO Naryanmarneftegaz (NMNG), a joint venture with LUKOIL. NMNG is working to develop resources in the northern part of Russia s Timan-Pechora province, including the Yuzhno Khylchuyu (YK) field. Initial production from YK was achieved in June 2008, with the field producing at a net rate of 24,000 barrels of oil per day at year end. Net peak production of 45,000 barrels per day is expected to be reached in the second quarter of 2009. Production from the NMNG joint venture fields is transported via pipeline to LUKOIL s terminal at Varandey Bay on the Barents Sea and then shipped via tanker to international markets. Late in the second quarter of 2008, LUKOIL completed an expansion of the terminal s gross oil-throughput capacity from 30,000 barrels per day to 240,000 barrels per day to accommodate production from the YK field.

Caspian

In the Caspian Sea, we have an interest in the Republic of Kazakhstan s North Caspian Sea Production Sharing Agreement (NCSPSA), which includes the Kashagan field. The first phase of field development currently being executed includes construction of artificial drilling islands with processing facilities and living quarters, and pipelines to carry production onshore. First production is expected in the latter part of 2012. The initial production phase of the contract is for 20 years, with options to extend the agreement an additional 20 years.

In 2004, the Republic of Kazakhstan approved the submitted development plan and budget relating to the Kashagan oil field development and, in 2007, triggered dispute proceedings under the NCSPSA following submission of a revised development plan and budget reflecting Kashagan cost increases and schedule delays. Definitive agreements were signed October 31, 2008, resolving the Kashagan field development dispute and allowing Kazakhstan s state-owned energy company, JSC National Company KazMunayGas, to increase its ownership interest from 8.33 percent to 16.81 percent. As a result, our interest in the NCSPSA was reduced from 9.26 percent to 8.40 percent, effective January 1, 2008. We will receive our share of the purchase price plus accrued interest in three annual installments beginning from the date of first commercial production. In addition, a new joint operating company, with significant involvement from the owners, was established and will operate future phases of Kashagan. We will have seconded employees in the joint operating company.

Transportation

We have a 2.5 percent interest in the Baku-Tbilisi-Ceyhan (BTC) pipeline, which transports crude oil from the Caspian region through Azerbaijan, Georgia and Turkey for tanker loadings at the port of Ceyhan.

Exploration

In October 2008, we signed a Memorandum of Understanding to negotiate terms for the exploration and development of the N Block, located offshore Kazakhstan, under a new subsoil use contract. Subsequently, in December 2008, we signed a Heads of Agreement that would give us a 24.5 percent interest in the exploration and development of the N Block. In addition, development studies continue for the next phase of Kashagan and the satellite fields of Kalamkas, Kairan and Aktote.

E&P OTHER

LNG

We have a long-term agreement with Freeport LNG Development, L.P. to use 0.9 billion cubic feet per day of regasification capacity at Freeport s 1.5-billion-cubic-feet-per-day LNG receiving terminal in Quintana, Texas. The terminal became operational late in the second quarter of 2008. In order to deliver natural gas from the Freeport terminal to market, we constructed a 32-mile, 42-inch pipeline from the Freeport terminal to a point near Iowa Colony, Texas. Construction was completed in the second quarter of 2008 to coincide with the

13

Table of Contents

Freeport terminal startup. Due to present market conditions, which favor the flow of LNG to European and Asian markets, our near-to-mid-term utilization of the Freeport terminal is expected to be limited. We are responsible for monthly process-or-pay payments to Freeport irrespective of whether we utilize the terminal for regasification. The financial impact of this capacity underutilization is not expected to be material to our future earnings or cash flows.
We received planning permission in 2008 for an LNG regasification facility and combined heat and power plant at the existing Norsea Pipeline Limited oil terminal site at Teesside, United Kingdom.

Commercial

Our Commercial organization optimizes the commodity flows of our E&P segment. This group markets our crude oil and natural gas production, using commodity buyers, traders and marketers in offices in the United States, the United Kingdom, Singapore, Canada and Dubai.

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, 2008. No difference exists between our estimated total proved reserves for year-end 2007 and year-end 2006, which are shown in this filing, and estimates of these reserves shown in a filing with another federal agency in 2008.

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 6 trillion cubic feet of natural gas and 119 million barrels of crude oil in the future, including approximately 800 billion cubic feet related to the minority interests of consolidated subsidiaries. These contracts have various expiration dates through the year 2025. We expect to fulfill the majority of these delivery commitments with proved developed reserves. In addition, we anticipate using proved undeveloped reserves and spot market purchases to fulfill these commitments. 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, 2008, our Midstream segment represented 1 percent of ConocoPhillips total assets. Our Midstream business is primarily conducted through our 50 percent equity investment in DCP Midstream, LLC, a joint venture with Spectra Energy.

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 2008, including our share of DCP Midstream, were 188,000 barrels per day, compared with 211,000 in 2007.

DCP Midstream markets a portion of its natural gas liquids to ConocoPhillips and Chevron Phillips Chemical Company LLC under a supply agreement that continues until December 31, 2014. This purchase commitment is on an if-produced, will-purchase basis and so 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 the 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, 2008, DCP Midstream owned or operated 53 natural gas liquids extraction and 10 natural gas liquids fractionation plants, and its gathering and transmission systems included approximately 60,000 miles of pipeline. In 2008, DCP Midstream s raw natural gas throughput averaged 6.2 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 363,000 barrels per day in 2007. DCP Midstream s assets are primarily located in the following producing regions of the United States: Rocky Mountains, Midcontinent, Permian, East Texas/North Louisiana, South Texas, Central Texas, and Gulf Coast.

Outside of DCP Midstream, our U.S. natural gas liquids business included the following as of year-end 2008:

- 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).
- A 12.5 percent equity interest in a fractionation plant in Mont Belvieu, Texas (with our net share of capacity at 26,000 barrels per day).

We also own a 39 percent equity interest in Phoenix Park Gas Processors Limited, a joint venture principally with the National Gas Company of Trinidad and Tobago Limited. Phoenix Park processes natural gas in Trinidad and markets natural gas liquids in the Caribbean, Central America and the U.S. Gulf Coast. Its facilities include a 1.35-billion-cubic-feet-per-day gas processing plant and a 70,000-barrel-per-day natural gas liquids fractionator. A third gas processing train is currently under construction and, when complete in 2009, will bring Phoenix Park s total processing capacity to 2 billion cubic feet per day. Our share of natural gas liquids extracted averaged 8,000 barrels per day in 2008 and 2007. Our share of fractionated liquids averaged 14,000 barrels per day in 2008, compared with 13,000 in 2007.

Table of Contents

REFINING AND MARKETING (R&M)

At December 31, 2008, our R&M segment represented 24 percent of ConocoPhillips total assets. R&M operations encompass refining crude oil and other feedstocks into petroleum products (such as gasolines, 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 the Asia Pacific region. The R&M segment does not include the results or statistics from our equity investment in LUKOIL, which are reported in our LUKOIL Investment segment.

Our 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, Canada and Dubai.

R&M UNITED STATES

Refining

At December 31, 2008, we owned or had an interest in 12 operated refineries in the United States.

		Net Crude Throughput Capacity (MBD)	
Refinery	Location	At December 31, 2008	Effective January 1, 2009
East Coast Region			
Bayway	Linden, New Jersey	238	238
Trainer	Trainer, Pennsylvania	185	185
		423	423
Gulf Coast Region			
Alliance	Belle Chasse, Louisiana	247	247
Lake Charles	Westlake, Louisiana	239	239
Sweeny	Old Ocean, Texas	247	247
		733	733
Central Region			
Wood River	Roxana, Illinois	153	153
Borger	Borger, Texas	95	73*
Ponca City	Ponca City, Oklahoma	187	187
		435	413
West Coast Region			
Billings	Billings, Montana	58	58
Ferndale	Ferndale, Washington	100	100
Los Angeles	Carson/Wilmington, California	139	139

San Francisco	Arroyo Grande/San Francisco, California	120	120
		417	417
		2,008	1,986

* *Amount reflects our 50 percent share of the Borger refinery effective January 1, 2009. We had a 65 percent share of Borger in 2008.*

Table of Contents

Primary crude oil characteristics and sources of crude oil for our U.S. refineries are as follows:

	Characteristics				Sources				
	Sweet	Medium Sour	Heavy Sour	High TAN*	United States	Canada	South America	Europe & FSU**	Middle East & Africa
Bayway									
Trainer									
Alliance									
Lake Charles									
Sweeny									
Wood River									
Borger									
Ponca City									
Billings									
Ferndale									
Los Angeles									
San Francisco									

* *High TAN (Total Acid Number): acid content greater than or equal to 1.0 milligram of potassium hydroxide (KOH) per gram.*

** *Former Soviet Union.*

Capacities for and yields of clean products, as well as other products produced, relating to our U.S. refineries are as follows:

	Clean Product Capacity (MBD)			Other Refined Product Output				
	Gasolines	Distillates	Clean Product Yield Capability	Fuel Oil & Other Heavy Intermediates	Natural Gas Liquids	Petroleum Coke	Petro-chemical Feedstock	Asphalt
Bayway	145	110	90%					
Trainer	105	65	85%					
Alliance	125	120	88%					
Lake Charles	90	110	69%			**		
Sweeny	130	120	86%					
Wood River*	83	45	80%					
Borger*	55	28	89%					

Ponca City	105	75	90%
Billings	35	25	89%
Ferndale	50	30	73%
Los Angeles	85	61	86%
San Francisco	50	45	72%

* *Represents our proportionate share as of January 1, 2009. In 2008, our share of Borger was 72 MBD gasolines and 36 MBD distillates.*

** *Includes specialty coke.*

<u>*MSLP*</u>

ConocoPhillips has a 50 percent interest in Merey Sweeny, L.P. (MSLP), a limited partnership that owns a 70,000-barrel-per-day delayed coker and related facilities at the Sweeny refinery that produce fuel-grade petroleum coke. Petróleos de Venezuela S.A. (PDVSA), which owns the other 50 percent interest, supplies the refinery with heavy, high-sulfur crude oil. We are the operator and managing partner. Late in 2008, PDVSA notified us that January 2009 nominated crude oil supplies for MSLP would not be delivered due to Venezuelan government-ordered production reductions. Similar notifications have been received for nominated supplies for February and March. We processed alternative crude oils at MSLP during January. Late in January, MSLP entered into a planned turnaround, which will continue into March 2009.

WRB

On January 3, 2007, we closed on a business venture with EnCana Corporation to create an integrated North American heavy oil business. The venture consists of two 50/50 business ventures: a Canadian upstream general partnership, the FCCL Oil Sands Partnership, and a U.S. downstream limited liability company, WRB Refining LLC. WRB consists of the Wood River and Borger refineries, located in Roxana, Illinois, and Borger, Texas, respectively. We are the operator and managing partner of WRB. For the Wood River refinery, operating results are shared 50/50. For the Borger refinery, we were entitled to 65 percent of the operating results in 2008, with our share decreasing to 50 percent in all years thereafter. See the Exploration and Production (E&P) section for additional information on FCCL.

Since formation, the joint venture has expanded the processing capability of heavy Canadian crude to 95,000 barrels per day from 60,000 barrels per day with the startup of a coker at Borger in 2007. In addition, during 2008, the final permit was received and plans were progressed to expand the Wood River refinery, including the installation of a coker. With the completion of this project, anticipated in 2011, total processing capability of heavy Canadian or similar crudes at Wood River will increase to 225,000 barrels per day, and existing asphalt production at the refinery will be replaced with production of upgraded products.

Capital Projects

In 2008, capital was directed toward projects to meet environmental and air emission standards and to further improve the operating reliability, safety and energy efficiency of processing units. In addition, capital was spent for small projects that are expected to yield an incremental return through providing improvements in overall transportation fuel yields and product mix.

Significant projects during 2008 included progressing an expansion of a hydrocracker at the Rodeo facility of our San Francisco refinery. When complete in 2009, this project is expected to increase clean product yield at the refinery. We also installed wet gas scrubbers at our Los Angeles and Ponca City refineries in order to improve air emissions from those plants. Another project completed during the year was a coker upgrade at our Los Angeles refinery, which improved the yield of transportation fuels.

Marketing

In the United States as of December 31, 2008, R&M marketed gasoline, diesel and aviation fuel through approximately 8,340 outlets in 49 states. The majority of these sites utilize the *Phillips 66*, *Conoco* or *76* brands.

Wholesale

At December 31, 2008, our wholesale operations utilized a network of marketers operating approximately 7,270 outlets that provided refined product offtake from our refineries, including Borger and Wood River. A strong emphasis is placed on the wholesale channel of trade because of its lower capital requirements. 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, we produce and market aviation gasoline, which is used by smaller, piston engine aircraft. At December 31, 2008, aviation gasoline and jet fuel were sold through independent marketers at approximately 630 *Phillips 66*-branded locations in the United States.

Retail

At December 31, 2008, our retail operations consisted of approximately 330 owned and operated sites under the *Conoco*, *Phillips 66* and *76* brands. Company-operated retail operations were focused in 10 states, mainly in the Midcontinent, Rocky Mountain and West Coast regions. Most of these outlets marketed merchandise through the *Kicks* or *Circle K* brand convenience stores.

At December 31, 2008, CFJ Properties, our 50/50 joint venture with Flying J, owned and operated approximately 110 truck travel plazas that carry the *Conoco*, *Flying J* or both brands. Flying J filed for Chapter 11 bankruptcy protection in December 2008. Flying J continues to operate the CFJ properties jointly owned with ConocoPhillips.

Table of Contents

In December 2006, we announced our U.S. company-owned and company-operated retail outlets and our U.S. company-owned and dealer-operated retail outlets would be divested to new or existing wholesale marketers. Approximately 830 sites were included in the held for sale plans. About 620 sites have been sold, including approximately 390 outlets sold in January 2009. The remaining sites included in the original disposition plan are also expected to be sold in 2009.

Transportation

We distribute refined products to our customers via company-owned and common-carrier pipeline, barge, railcar and truck.

Pipelines and Terminals

At December 31, 2008, R&M had approximately 28,000 miles of common-carrier crude oil, raw natural gas liquids, and petroleum products pipeline systems in the United States, including those partially owned or operated by affiliates. We also owned or operated 48 finished product terminals, seven liquefied petroleum gas terminals, five crude oil terminals and one coke exporting facility.

In December 2007, we acquired a 50 percent equity interest in four Keystone pipeline entities (Keystone), to create a joint venture with TransCanada Corporation. In October 2008, we elected to exercise an option to reduce our equity interest from 50 percent to 20.01 percent. The change in equity will occur through a dilution mechanism, which is expected to gradually lower our ownership interest until it reaches 20.01 percent by the third quarter of 2009. At December 31, 2008, our ownership interest was 38.7 percent. Keystone s first phase, a 2,148-mile, 590,000-barrel-per-day crude oil pipeline from Alberta to delivery points in Illinois and Oklahoma, is expected to be mechanically complete in late 2009. A second phase is expected to carry up to 700,000 barrels per day to refineries on the Gulf Coast. We anticipate utilizing the Keystone pipeline to transport our Canadian crude oil production to market, including as a source of supply to our U.S. refineries.

Tankers

During 2008, we disposed of our international marine operations consisting of leasehold interests in six double-hulled crude oil tankers and replaced the disposed operations with long-term charter agreements. At December 31, 2008, we had 17 double-hulled crude oil tankers, with capacities ranging in size from 700,000 to 2,100,000 barrels, which are under charter primarily to transport feedstocks to certain of our U.S. refineries. In addition, we had under charter five double-hulled product tankers utilized to transport our heavy and clean products. The tankers discussed here exclude the operations of the company s subsidiary, Polar Tankers, Inc., which are discussed in the E&P segment, 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. Our lubes are marketed under the *Phillips 66*, *Conoco*, *76* and *Kendall* brands. We also manufacture and market high-quality graphite and anode-grade petroleum cokes in the United States and Europe for use in the global steel and aluminum industries.

The company s 50-percent-owned Excel Paralubes joint venture owns a hydrocracked lubricant base oil manufacturing plant located adjacent to the Lake Charles refinery. The facility produces approximately 20,000 barrels per day of high-quality, clear hydrocracked base oils.

In January 2008, we sold our 50 percent interest in Penreco, which manufactured and marketed highly refined specialty petroleum products.

Table of Contents

R&M INTERNATIONAL

Refining

At December 31, 2008, R&M owned or had an interest in five refineries outside the United States.

	Location	Ownership	Net Crude Throughput Capacity (MBD) At December 31, 2008	Effective January 1, 2009
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	58	58
Melaka	Melaka, Malaysia	47.00	60	61
			670	671

* *Mineraloel Raffinerie Oberrhein GmbH.*

Primary crude oil characteristics and sources of crude oil for our international refineries are as follows:

	Characteristics: Sweet	Medium Sour	Heavy Sour	High TAN*	Sources: Europe & FSU**	Middle East & Africa
Humber						
Whitegate						
Wilhelmshaven						
MiRO						
Melaka						

* *High TAN (Total Acid Number): acid content greater than or equal to 1.0 milligram of potassium hydroxide (KOH) per gram.*

** *Former Soviet Union.*

Capacities for and yields of clean products, as well as other products produced, relating to our international refineries are as follows:

	Clean Product Capacity (MBD)			Other Refined Product Output			
	Gasolines	Distillates	Clean Product Yield Capability	Fuel Oil & Other Heavy Intermediates	Natural Gas Liquids	Petroleum Coke	Asphalt
Humber	84	119	84%			*	
Whitegate	18	30	65%				
Wilhelmshaven	36	102	53%				
MiRO	25	26	85%				
Melaka	14	36	85%				

* *Includes specialty coke.*

Table of Contents

We operate a crude oil and products storage complex consisting of 7.5 million barrels of storage capacity and an offshore mooring buoy, located about 80 miles southwest of the Whitegate refinery in Bantry Bay, Ireland.

During 2008, we continued to progress our plans to upgrade the Wilhelmshaven refinery in Germany. Our future capital budget incorporates funds to economically improve the operation of the refinery, enabling it to process heavier, higher-sulfur crude oil and produce predominantly low-sulfur diesel.

In late 2007, we and our co-venturers sanctioned a project for the expansion of the Melaka refinery to be completed during 2010. This project is intended to increase crude oil, conversion and treating unit capacities.

In May 2006, we signed a Memorandum of Understanding with Saudi Aramco to conduct a detailed evaluation of the 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. In November 2008, we agreed to delay the bidding process associated with the refinery s construction due to uncertainties in the contracting and financial markets. The originally scheduled bidding process requested bids be submitted in December 2008. Instead, project bidding is now scheduled to begin in 2009.

Marketing

At December 31, 2008, R&M had marketing operations in five 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 use the *JET* brand name to market retail and wholesale products in Austria, Germany 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 market aviation fuels, liquid petroleum gases, heating oils, transportation fuels and marine bunkers to commercial customers and into the bulk or spot market in the aforementioned countries and Ireland.

As of December 31, 2008, R&M had approximately 1,260 marketing outlets in its European operations, of which approximately 860 were company-owned and 400 were dealer-owned. Through our joint venture operations in Switzerland, we also have interests in 200 additional sites. In October 2008, we sold our 274 fueling stations in Norway, Sweden and Denmark to Statoil.

LUKOIL INVESTMENT

At December 31, 2008, our LUKOIL Investment segment represented 4 percent of ConocoPhillips total assets. In 2004, we became a strategic equity investor in OAO LUKOIL, an international, integrated oil and gas company headquartered in Russia. Under the Shareholder Agreement between the two companies, we have representation on the LUKOIL Board of Directors, and LUKOIL s corporate charter requires unanimous Board consent for certain key decisions. At year-end 2008, we had a 20 percent ownership interest in LUKOIL based on authorized and issued shares. Based on estimated shares outstanding at year end, our ownership was 20.06 percent. We use the equity method of accounting for our investment in LUKOIL. See Note 7 Investments, Loans and Long-Term Receivables, in the Notes to Consolidated Financial Statements, for additional information.

As reported in LUKOIL s publicly available 2007 annual report, the majority of its 2007 upstream oil production was sourced within Russia, with 62 percent from the western Siberia region, 15 percent from the Timan-Pechora province and 12 percent from the Urals region. Outside of Russia, LUKOIL had 2007 oil production in Kazakhstan, Egypt and Azerbaijan, and gas production in Uzbekistan. Eighty-eight percent of LUKOIL s natural gas production was sourced within Russia. In addition, LUKOIL has an active exploration program focused in Russia but also encompassing several international countries. Downstream, LUKOIL has seven refineries with a net crude oil throughput capacity of approximately 1.2 million barrels per day. LUKOIL also has a marketing network extending to 24 countries, with the majority of wholesale and retail sales in Russia, the United States and Europe.

CHEMICALS

At December 31, 2008, our Chemicals segment represented 2 percent of ConocoPhillips total assets. The Chemicals segment consists of our 50 percent equity investment in Chevron Phillips Chemical Company LLC (CPChem), a joint venture with Chevron Corporation, headquartered in The Woodlands, Texas.

CPChem s business is structured around two primary operating segments: Olefins & Polyolefins and Specialties, Aromatics & Styrenics. 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, polypropylene, and polyethylene pipe. The Specialties, 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. Furthermore, this segment manufactures and markets a variety of specialty chemical products including organosulfur chemicals, solvents, catalysts, drilling chemicals, mining chemicals and high-performance engineering plastics and compounds.

CPChem s domestic facilities are located in California, Connecticut, Illinois, Louisiana, Mississippi, Ohio and Texas. International facilities are located in Belgium, Brazil, China, Columbia, Qatar, Saudi Arabia, Singapore and South Korea.

CPChem owns a 49 percent interest in Qatar Chemical Company Ltd. (Q-Chem), a joint venture that owns a major olefins and polyolefins complex in Mesaieed, Qatar. CPChem also owns a 49 percent interest in Qatar Chemical Company II Ltd. (Q-Chem II), a joint venture that began construction of a second complex in Mesaieed in 2005. This Q-Chem II facility is designed to produce polyethylene and normal alpha olefins on a site adjacent to the Q-Chem complex. In connection with this project, CPChem entered into a separate agreement establishing a joint venture to develop an ethylene cracker in Ras Laffan Industrial City, Qatar. Operational startup of the Q-Chem II project is anticipated in late 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 is being built adjacent to the existing aromatics complex owned by Saudi Chevron Phillips Company (SCP), another 50-percent-owned CPChem joint venture. 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 occurred in the third quarter of 2008, while project completion is anticipated during the first quarter of 2009.

In 2007, CPChem formed a 50-percent-owned joint venture, Saudi Polymers Company (SPC), to construct and operate an integrated petrochemicals complex at Al Jubail, Saudi Arabia. Construction began in January 2008, and commercial production is scheduled to begin in late 2011. Prior to project completion, based on a planned initial public offering of shares in CPChem s joint venture partner s company and a corresponding increase in the partner s ownership interest in SPC, CPChem s ownership is expected to decline to 35 percent.

In 2007, CPChem and the Dow Chemical Company signed a nonbinding Memorandum of Understanding relating to the formation of a joint venture involving assets from their polystyrene and styrene monomer businesses. Joint venture operations commenced in May 2008, with CPChem contributing two domestic plants and Dow contributing four domestic and two international plants.

EMERGING BUSINESSES

At December 31, 2008, our Emerging Businesses segment represented 1 percent of ConocoPhillips total assets. The segment encompasses the development of new technologies and businesses outside our normal scope of operations. Activities within this segment are currently focused on power generation and innovation of new technologies, such as those related to conventional and nonconventional hydrocarbon recovery (including heavy oil), refining, alternative energy, biofuels and the environment.

Table of Contents

The focus of our power business is on developing projects to support our E&P and R&M strategies. While projects primarily in place to enable these strategies are included within their respective segments, projects with a significant merchant component are included in the Emerging Businesses segment.

The Immingham combined heat and power plant (CHP), a wholly owned 730-megawatt facility in the United Kingdom, 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 expand capacity at Immingham 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 expected to start in mid-2009.

We also own a gas-fired cogeneration plant in Orange, Texas, as well as a 50 percent operating interest in Sweeny Cogeneration LP, a joint venture near the Sweeny refinery complex.

Our Technology group focuses on developing new business opportunities designed to provide future growth prospects for ConocoPhillips. Areas of interest include advanced hydrocarbon processes, energy conversion technologies, new petroleum-based products, renewable fuels and carbon capture technology. We have commercialized production of renewable diesel, a new type of renewable fuel that utilizes existing infrastructure. In 2007, we formed a research relationship with Iowa State University to develop new methods for producing second-generation biofuels. In addition, we have formed alliances with Tyson Foods and Archer Daniels Midland to produce and market the next generation of renewable transportation fuels. We have also formed an internal group that is evaluating wind, solar and geothermal investment opportunities.

We are working with General Electric Company to develop a technology center in Qatar to research water sustainability solutions for petroleum, petrochemical, municipal and agricultural applications. The Qatar center will examine ways of treating and using by-product water from oil production and refining operations, as well as other projects relating to industrial and municipal water sustainability. In conjunction with the Interim Agreement to develop the Shah field with the Abu Dhabi National Oil Company, we are planning to develop a technology center in Abu Dhabi that will conduct research and provide technical service in areas including reservoir management and development of sour gas fields; safe and efficient processing of gas with high hydrogen sulfide and carbon dioxide concentrations; and sour gas sequestration. Both centers are expected to open in 2009.

We offer a gasification technology (E-Gas) that uses petroleum coke, coal, and other low-value hydrocarbons as feedstock, resulting in high-value synthesis gas used for a slate of products, including power, hydrogen and chemicals. In 2008, we completed a feasibility study and submitted applications for all required environmental permits related to a proposed coal-to-substitute natural gas (SNG) facility, which would have a capacity of 60 billion to 70 billion cubic feet per year and be located in Muhlenberg County, Kentucky. We also became a founding member of the Western Kentucky Carbon Storage Foundation, which is funding evaluation of carbon storage in deep underground formations through a test well project directed by the Kentucky Geologic Survey.

A conceptual engineering study was completed in 2008 for a project at our Sweeny refinery in Texas that would utilize E-Gas technology to convert petroleum coke to low-carbon power or SNG and hydrogen. To minimize carbon dioxide (CO2) emissions from the facility, the proposed design allows CO2 to be captured, transported and safely stored in nearby geological formations. This project would increase clean energy supply while establishing critical carbon capture and storage infrastructure in the Texas Gulf Coast region. A more detailed feasibility study is expected in 2009.

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 our segments is highly competitive. No single competitor, or small group of competitors, dominates any of our business lines.

Table of Contents

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 2007 reserves statistics, we had the sixth-largest total of worldwide proved reserves of nongovernment-controlled companies. We deliver our oil and natural gas production into the worldwide oil and natural gas commodity markets. Principal methods of competing include geological, geophysical and engineering research and technology; experience and expertise; economic analysis in connection with property acquisitions; and operating efficient oil and gas producing properties.

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 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. Principal methods of competing include economically securing the right to purchase raw natural gas into gathering systems, managing the pressure of those systems, operating efficient natural gas liquids processing plants, and securing markets for the products produced.

Downstream, our R&M segment competes primarily in the United States, Europe and the Asia Pacific region. Based on the statistics published in the December 22, 2008, issue of the *Oil & Gas Journal*, our R&M segment had the second-largest U.S. refining capacity of 18 large refiners of petroleum products. Worldwide, our refining capacity ranked fourth among nongovernment-controlled companies. In the Chemicals segment, CPChem generally ranked within the top 10 producers of many of its major product lines, based on average 2008 production capacity, as published by industry sources. Petroleum products, petrochemicals and plastics are delivered into the worldwide commodity markets. Elements of competition for both our R&M and Chemicals segments include product improvement, new product development, low-cost structures, and improved manufacturing and distribution systems. In the marketing portion of the business, competitive factors include product properties and processibility, reliability of supply, customer service, price and credit terms, advertising and sales promotion, and development of customer loyalty to ConocoPhillips or CPChem s branded products.

GENERAL

At the end of 2008, we held a total of 1,464 active patents in 81 countries worldwide, including 556 active U.S. patents. During 2008, we received 39 patents in the United States and 58 foreign patents. Our products and processes generated licensing revenues of $38 million in 2008. 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 $209 million, $160 million, and $117 million in 2008, 2007, and 2006, respectively.

The environmental information contained in Management s Discussion and Analysis of Financial Condition and Results of Operations on pages 63 through 65 under the caption Environmental is incorporated herein by reference. It includes information on expensed and capitalized environmental costs for 2008 and those expected for 2009 and 2010.

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 U.S. Securities and Exchange Commission (SEC). Alternatively, you may access these reports at the SEC s Web site at *http://www.sec.gov*.

Table of Contents

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.

Our operating results, our future rate of growth and the carrying value of our assets are exposed to the effects of changing commodity prices and refining margins.

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. The factors influencing the prices of crude oil, natural gas, natural gas liquids and refined products are beyond our control. Lower crude oil, natural gas, natural gas liquids and refined products prices may reduce the amount of these commodities we can produce economically, which may have a material adverse effect on our revenues, operating income and cash flows.

Unless we successfully add to our existing proved reserves, our future crude oil and natural gas production will decline, resulting in harm to our business.

The rate of production from crude oil and natural gas properties generally declines as reserves are depleted. Except to the extent that we 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 suffer reduced cash flows and results of operations.

Any material change in the factors and assumptions underlying our estimates of crude oil and natural gas reserves could impair the quantity and value of those reserves.

Our proved crude oil and natural gas reserve information included in this annual report has been derived from engineering estimates prepared or reviewed by our personnel. 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. 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. Any changes in the factors and assumptions underlying our estimates of these items could result in a material negative impact to the volume of reserves reported.

We expect to continue to incur substantial capital expenditures and operating costs as a result of our compliance with existing and future environmental laws and regulations. Likewise, future environmental laws and regulations may impact or limit our current business plans and reduce demand for our products.

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.
- Emissions into the atmosphere (such as nitrogen oxides, sulfur dioxide and mercury emissions, or potential future control of greenhouse gas emissions).

Table of Contents

The handling, use, storage, transportation, disposal and clean up of hazardous materials and hazardous and nonhazardous 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 business, financial condition, results of operations and cash flows in future periods could be materially adversely affected.

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

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, such as the expropriation of our oil assets by the Venezuelan government, and will continue to do so in the future.

Local political and economic factors in international markets could have a material adverse effect on us. Approximately 56 percent of our crude oil, natural gas and natural gas liquids production in 2008 was derived from production outside the United States, and 62 percent of our proved reserves, as of December 31, 2008, were located outside the United States. We are subject to 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.

The current financial crisis could have a material adverse affect on our financial strength and that of our business co-venturers.

Recent disruptions in the credit markets and concerns about global economic growth have had a significant adverse impact on global financial markets and commodity prices, both of which have contributed to a decline in our stock price and corresponding market capitalization. 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. Decreased returns on pension fund assets may also materially increase our pension funding requirements. Likewise, the capital and credit markets have become increasingly volatile as a result of adverse conditions. If the capital and credit markets continue to experience volatility and the availability of funds remains limited, we, and third parties with whom we do business, may incur increased costs associated with issuing commercial paper and/or other debt instruments and this, in turn, could adversely affect our ability to advance our strategic plans as currently contemplated. In this context, changes in our debt rating could have a material adverse effect on our interest costs and financing sources.

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 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 participants. There is a risk that our joint venture participants may at any time have economic, business or legal interests or goals that are inconsistent with those of the joint venture or us, or that our joint venture participants 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.

Our operations are inherently dangerous and require significant and continuous oversight.

The scope and nature of our operations present a variety of operational hazards and risks that must be managed through continual oversight and control. These risks are present throughout the process of extraction, transportation, refinement and storage of the hydrocarbons we produce. Failure to manage these risks could result in injury or loss of life, environmental damage, loss of revenues and damage to our reputation.

Item 1B. UNRESOLVED STAFF COMMENTS

None.

Item 3. LEGAL PROCEEDINGS

The following is a description of reportable legal proceedings, including those involving governmental authorities under federal, state and local laws regulating the discharge of materials into the environment for this reporting period. The following proceedings include those matters that arose during the fourth quarter of 2008, as well as matters previously reported in our 2007 Form 10-K and our first-, second- and third-quarter 2008 Form 10-Qs that were not resolved prior to the fourth quarter of 2008. Material developments to the previously-reported matters have been included in the descriptions below. 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, we expect 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.

Our U.S. refineries are implementing two separate consent decrees, regarding alleged violations of the Federal Clean Air Act, with the U.S. Environmental Protection Agency (EPA), six states and one local air pollution agency. Some of the requirements and limitations contained in the decree provide for stipulated penalties for violations. Stipulated penalties under the decrees are not automatic, but must be requested by one of the agency signatories. As part of periodic reports under the decree and/or other reports required by permits or regulations, we occasionally report matters which could be subject to a request for stipulated penalties. If a specific request for stipulated penalties meeting the reporting threshold set forth in U.S. Securities and Exchange Commission rules is made pursuant to these decrees based on a given reported exceedance, we will separately report that matter and the amount of the proposed penalty.

New Matters

On October 23, 2008, ConocoPhillips received a demand from the Los Angeles Regional Water Quality Control Board (LARWQCB) to settle multiple alleged exceedances of National Pollutant Discharge Elimination System Permit effluent limits at its Los Angeles Lubricants plant dating back to 2000. The amount of the demand is $174,000. We will work with the LARWQCB to resolve these allegations.

On December 15, 2008, the Trainer refinery received Citations and a Notification of Penalty (Citation) from the Occupational Safety and Health Administration (OSHA) for 26 alleged violations noted during the OSHA National Emphasis Program review of the refinery. The Citation seeks $115,500 in penalties for a variety of alleged Process Safety Management violations. We are working with OSHA to resolve this matter.

Matters Previously Reported

The South Coast Air Quality Management District (SCAQMD) conducted an audit of the Los Angeles refinery in 2007 to assess compliance with applicable local, state, and federal regulations related to fugitive emissions. As a result of the audit, SCAQMD issued three Notices of Violations (NOVs) alleging multiple counts of noncompliance. We resolved two of the three NOVs for a total payment of $42,500 in the third quarter of 2008 and reached an agreement with SCAQMD to resolve the third NOV for $12,500 in the fourth quarter of 2008.

SCAQMD conducted an audit of the Los Angeles refinery in August 2008 to assess compliance with applicable local, state and federal regulations related to fugitive emissions. As a result of the audit, on August 28, 2008, SCAQMD issued five NOVs alleging noncompliance. SCAQMD has not yet specified a penalty for these alleged violations. We are working with SCAQMD to resolve these NOVs.

On July 16, 2008, ConocoPhillips received a demand from the Bay Area Air Quality Management District (BAAQMD) to settle 24 NOVs issued in late 2006 and 2007 for alleged violations of air pollution-control regulations at the San Francisco refinery. The amount of the settlement demand is $304,500. On December 29, 2008, BAAQMD added an additional seven NOVs issued in 2008 and a corresponding additional $340,500 to its settlement demand. We are working with BAAQMD to resolve these NOVs.

On June 2, 2008, the Billings refinery received a Violation Letter from the Montana Department of Environmental Quality (MDEQ) for opacity and nickel emissions, which occurred during startup of the catalytic cracker in April 2007. The letter also alleged certain monitoring quality assurance/quality control violations. The letter requests a penalty of $604,000. We intend to work with the MDEQ to resolve this matter.

On March 27, 2008, the Trainer refinery received a proposed Consent Assessment of Civil Penalty from the Pennsylvania Department of Environmental Protection (PADEP) for alleged air quality violations that occurred from 2002 to 2007. The assessment covers several categories of alleged air quality violations including emission events, air emissions inventory reporting, and violation of permit conditions. We paid $129,424 in the fourth quarter of 2008 to resolve this matter.

On March 27, 2008, the Sweeny refinery received a Notice of Enforcement (NOE) from the Texas Commission on Environmental Quality (TCEQ) for an emissions event related to flaring that occurred on January 28, 2008. A penalty of $32,000 was submitted to the TCEQ in September 2008. This matter is subject to formal approval by the TCEQ Commissioners. We expect consideration of approval to occur in the first quarter of 2009.

On February 11, 2008, ConocoPhillips Alaska, Inc. (CPAI) received an NOV from the North Slope Borough (NSB) in relation to its Alpine facility on the North Slope of Alaska. The NOV alleges that three fuel tanks at the Alpine facility lacked adequate containment and/or setbacks from water bodies. There was no environmental impact due to these alleged violations. The NOV proposed penalties of $207,000, which was later reduced to $128,000. CPAI paid the reduced penalty under protest in accordance with the payment demands in the NOV. On March 11, 2008, CPAI filed an appeal with the NSB Planning Commission challenging the alleged violations and penalties in the NOV. We will continue to work with the NSB to resolve this matter.

In October 2003, the District Attorney s Office in Sacramento, California, filed a complaint in Superior Court for alleged methyl tertiary-butyl ether (MTBE) contamination in groundwater. On April 4, 2008, the District Attorney s Office filed an amended complaint that included alleged violations of state regulations relating to operation or maintenance of underground storage tanks. There are numerous defendants named in the suit in addition to ConocoPhillips. We intend to continue to contest this lawsuit.

In October 2007, we received a Complaint from the U.S. EPA alleging violations of the Clean Water Act related to a 2006 oil spill at our Bayway refinery and proposing a penalty of $156,000. We are working with the EPA and the U.S. Coast Guard to resolve this matter.

On December 16, 2005, the Bayway refinery experienced a hydrocarbon spill to the Rahway River and Arthur Kill. On August 26, 2006, we signed an Order on Consent with the state of New York pursuant to which we paid a penalty of $50,000 and conducted a beach cleanup. Also in December 2008, we paid a total of $106,578 for natural resource damages and other costs to the New Jersey Department of Environmental Protection, the U.S. Department of the Interior and the U.S. Department of Commerce. This matter is resolved.

In March 2005, ConocoPhillips Pipe Line Company (CPPL) received a Notice of Probable Violation and Proposed Civil Penalty from the U.S. Department of Transportation s Pipeline and Hazardous Materials Safety Administration (DOT) alleging violation of DOT operation and safety regulations at certain facilities in Kansas, Missouri, Illinois, Indiana, Wyoming and Nebraska. DOT is proposing penalties in the amount of $184,500. An information hearing was held on September 24, 2007. CPPL has provided additional information in support of its position. We are currently awaiting a ruling from DOT.

The U.S. Coast Guard and Washington State Department of Ecology investigated the possible sources of an oil spill in Puget Sound. In November 2004, the U.S. Attorney and the U.S. Coast Guard offices in Seattle, Washington, issued subpoenas to Polar Tankers, Inc., a subsidiary of ConocoPhillips Company, for records related to the vessel Polar Texas. On December 23, 2004, the governor of the state of Washington and the U.S. Coast Guard publicly announced they believed the Polar Texas was the source of the spill. The company fully cooperated with the investigations. The U.S. Attorney s Office in Seattle declined prosecution of the company. As previously reported, Polar Tankers, ConocoPhillips and the state of Washington settled the matter, with payment of civil penalties and response costs. The settlement did not include any admission of liability. The company and the authorities remain in settlement negotiations regarding the natural resource damage assessment.

In April 2004, in response to several historical spills at the Albuquerque Products Terminal, we received an Administrative Compliance Order from the New Mexico Environment Department. The order does not propose a penalty assessment, but rather attempts to impose specific design, construction and operational changes. We have been in negotiations with the agency and in June 2007 proposed a settlement offer of $100,000. We will continue to work with the agency to resolve this matter.

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

None.

Table of Contents

EXECUTIVE OFFICERS OF THE REGISTRANT

Name	Position Held	Age*
Rand C. Berney	Vice President and Controller	53
John A. Carrig	President and Chief Operating Officer	57
W. C. W. Chiang	Senior Vice President, Refining, Marketing and Transportation	48
Sigmund L. Cornelius	Senior Vice President, Finance, and Chief Financial Officer	54
James L. Gallogly	Executive Vice President, Exploration and Production	56
Janet L. Kelly	Senior Vice President, Legal, General Counsel and Corporate Secretary	51
James J. Mulva	Chairman of the Board of Directors and Chief Executive Officer	62
Jeff W. Sheets	Senior Vice President, Planning and Strategy	51

* *On February 15, 2009.*

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 13, 2009. Set forth below is information about the executive officers.

Rand C. Berney was appointed Vice President and Controller upon completion of the merger in 2002.

John A. Carrig was appointed President and Chief Operating Officer in October 2008, having previously served as Executive Vice President, Finance, and Chief Financial Officer since the merger in 2002.

W. C. W. Chiang was appointed Senior Vice President, Refining, Marketing and Transportation in October 2008. He previously served as Senior Vice President, Commercial since 2007. Prior to that, he served as President, Americas Supply & Trading, Commercial, from 2005 through 2007 and as President, Downstream Strategy, Integration and Specialty Businesses from 2003 through 2005.

Sigmund L. Cornelius was appointed Senior Vice President, Finance, and Chief Financial Officer in October 2008. Prior to that, he served as Senior Vice President, Planning, Strategy and Corporate Affairs since September 2007, having previously served as President, Exploration and Production Lower 48 since 2006. He served as President, Global Gas since 2004, and prior to that served as President, Lower 48, Latin America and Midstream since 2003.

James L. Gallogly was appointed Executive Vice President, Exploration and Production in October 2008, and prior to that served as Executive Vice President, Refining, Marketing and Transportation from April 2006. He previously served as President and Chief Executive Officer of Chevron Phillips Chemical Company LLC since 2000.

Janet L. Kelly was appointed Senior Vice President, Legal, General Counsel and Corporate Secretary effective September 1, 2007, having previously served as Deputy General Counsel since 2006. Prior to joining ConocoPhillips in 2006, she was a partner at Zelle, Hoffman, Voelbel, Mason and Gette during 2005 and 2006. She previously served as Senior Vice President, Chief Administrative Officer and Chief Compliance Officer of Kmart Corporation during 2003 and 2004.

James J. Mulva has served as Chairman of the Board of Directors and Chief Executive Officer since October 2008, having previously served as Chairman of the Board of Directors, President and Chief Executive Officer since October 2004. Prior to that, he served as President and Chief Executive Officer since completion of the merger in 2002.

Jeff W. Sheets was appointed Senior Vice President, Planning and Strategy in October 2008, having previously served as Vice President and Treasurer since the merger in 2002.

Table of Contents

PART II

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

Quarterly Common Stock Prices and Cash Dividends Per Share

ConocoPhillips common stock is traded on the New York Stock Exchange, under the symbol COP.

	Stock Price High	Stock Price Low	Dividends
2008			
First	**$ 89.71**	**67.85**	**.47**
Second	**95.96**	**75.52**	**.47**
Third	**94.65**	**67.31**	**.47**
Fourth	**72.25**	**41.27**	**.47**
2007			
First	$ 71.50	61.59	.41
Second	81.40	66.24	.41
Third	90.84	73.75	.41
Fourth	89.89	74.18	.41

Closing Stock Price at December 31, 2008	$ 51.80
Closing Stock Price at January 31, 2009	$ 47.53
Number of Stockholders of Record at January 31, 2009*	62,887

* *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, 2008	12,642,418	$ 58.97	12,578,250	$ 1,855
November 1-30, 2008	2,090	50.57		1,855
December 1-31, 2008	65	50.18		

Total	12,644,573	$	58.96	12,578,250

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

** *On January 12, 2007, we announced a stock repurchase program that provided for the repurchase of up to $1 billion of the company s common stock. On February 9, 2007, we announced plans to repurchase $4 billion of our common stock in 2007, including the $1 billion announced on January 12, 2007. On July 9, 2007, we announced plans to repurchase up to $15 billion of the company s common stock through the end of 2008, which included the $2 billion remaining under the previously* *announced $4 billion program. Acquisitions for the share repurchase programs are made at management s discretion, at prevailing prices, subject to market conditions and other factors. Repurchases may be increased, decreased or discontinued at any time without prior notice. Shares of stock repurchased under the plans are held as treasury shares.*

Table of Contents

Item 6. SELECTED FINANCIAL DATA

	Millions of Dollars Except Per Share Amounts				
	2008	2007	2006	2005	2004
Sales and other operating revenues	**$ 240,842**	187,437	183,650	179,442	135,076
Income (loss) from continuing operations	**(16,998)**	11,891	15,550	13,640	8,107
Per common share					
Basic	**(11.16)**	7.32	9.80	9.79	5.87
Diluted	**(11.16)**	7.22	9.66	9.63	5.79
Net income (loss)	**(16,998)**	11,891	15,550	13,529	8,129
Per common share					
Basic	**(11.16)**	7.32	9.80	9.71	5.88
Diluted	**(11.16)**	7.22	9.66	9.55	5.80
Total assets	**142,865**	177,757	164,781	106,999	92,861
Long-term debt	**27,085**	20,289	23,091	10,758	14,370
Joint venture acquisition obligation related party	**5,669**	6,294			
Cash dividends declared per common share	**1.88**	1.64	1.44	1.18	.895

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 financial data for 2008 includes the impact of impairments relating to goodwill and to our LUKOIL investment that together amount to $32,853 million before- and after-tax. For additional information, see the Goodwill Impairment section of Note 9 Goodwill and Intangibles and the LUKOIL section of Note 7 Investments, Loans and Long-Term Receivables, in the Notes to Consolidated Financial Statements.

The financial data for 2007 includes the impact of a $4,588 million before-tax ($4,512 million after-tax) impairment related to the expropriation of our oil interests in Venezuela. For additional information, see the Expropriated Assets section of Note 10 Impairments, in the Notes to Consolidated Financial Statements.

Additionally, the acquisition of Burlington Resources in 2006 affects the comparability of the amounts included in the table above. See Note 3 Acquisition of Burlington Resources Inc., in the Notes to Consolidated Financial Statements, for additional information. 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 amounts included in the table above.

Table of Contents

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

February 25, 2009

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, pla scheduled, should, anticipates, estimates and similar expressions identify forward-looking statements. The compan 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 72.

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 33,800 employees worldwide, and at year-end 2008 had assets of $143 billion. Our stock is listed on the New York Stock Exchange under the symbol COP.

Our business is organized into six operating segments:

- **Exploration and Production (E&P)** This segment primarily explores for, produces, transports 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, predominantly in the United States and Trinidad. The Midstream segment primarily consists of our 50 percent equity investment in DCP Midstream, 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, an international, integrated oil and gas company headquartered in Russia. At December 31, 2008, our ownership interest was 20 percent based on issued shares and 20.06 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 represents our investment in new technologies or businesses outside our normal scope of operations.

Table of Contents

In 2008, the energy industry was characterized by extreme volatility. Forecasts of worldwide economic growth and increasingly scarce supply, a weakening U.S. dollar, and other factors helped drive crude oil prices to record highs. This was followed by an abrupt shift into a severe global financial recession, which reduced current and forecasted demand for petroleum products. Because of this, crude oil prices fell rapidly and refining margins also significantly weakened.

As a result of the significant drop in global equity markets during the fourth quarter of 2008, we recorded two individually significant impairments in 2008 that were primarily linked to market capitalizations a $25.4 billion write-down of our E&P segment s recorded goodwill, and a $7.4 billion reduction in the carrying value of our LUKOIL investment. These impairments contributed to a net loss in 2008 of $17.0 billion, compared with net income in 2007 of $11.9 billion, which includes the impact of a $4.5 billion impairment due to expropriation of our Venezuelan assets. Since these 2008 and 2007 impairment charges were noncash, they did not impact our cash provided by operating activities, which was $22.7 billion in 2008, compared with $24.6 billion in 2007.

Crude oil and natural gas prices, along with refining margins, are the most significant factors in our profitability, and 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:

<u>Operating our producing properties and refining and marketing operations safely, consistently and in an environmentally sound manner.</u> Safety is our first priority, and we are committed to protecting the health and safety of everyone who has a role in our operations 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 2008, our worldwide refining capacity utilization rate was 90 percent, compared with 94 percent in 2007. The lower rate primarily reflects reduced throughput at our Wilhelmshaven, Germany, refinery due to economic conditions, as well as higher unplanned downtime including impacts from hurricanes in the U.S. Gulf Coast region. Concerning the environment, we strive to conduct our operations in a manner consistent with our environmental stewardship principles.

<u>Adding to our proved reserve base.</u> 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 the three years ending December 31, 2008, our reserve replacement was 124 percent, including the impacts of the Burlington Resources acquisition, additional equity investments in LUKOIL, the FCCL Oil Sands Partnership with EnCana, the Australia Pacific LNG joint venture with Origin Energy, and the expropriation of our Venezuelan oil assets.

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.

<u>Controlling costs and expenses.</u> Since we cannot control the prices of the commodity products we sell, controlling operating and overhead costs, 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 is critical to maintaining competitive positions in our

Table of Contents

industries, cost control is a component of our variable compensation programs. In response to the current depressed market environment, we expect to reduce our work force in 2009, reduce the headcount of contractors, and continue to emphasize cost discipline throughout our operations.

With the rise in commodity prices over the last several years and through the first half of 2008, and the subsequent increase in industry-wide spending on capital and major maintenance programs, we and other energy companies experienced inflation for the costs of certain goods and services in excess of general worldwide inflationary trends. Such costs included rates for drilling rigs, steel and other raw materials, as well as costs for skilled labor. With the weakening of the economy and the decline in commodity prices, our industry began to see some relief from this upward cost pressure in late 2008 and into early 2009.

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.

In October 2008, we formed Australia Pacific LNG, a 50/50 joint venture with Origin Energy for the development of coalbed natural gas in Australia, and the subsequent liquefaction and transport of the liquefied natural gas targeting Asia Pacific markets. In January 2007, we entered into two 50/50 business ventures with EnCana to create an integrated North American heavy oil business, consisting of the upstream FCCL Oil Sands Partnership in Canada and the downstream WRB Refining LLC in the United States.

Our capital expenditures and investments in 2008 totaled $19.1 billion, and we anticipate capital expenditures and investments to be approximately $11.7 billion in 2009. The reduced capital budget in 2009 reflects the impact of the Origin transaction on the 2008 totals, and a planned reduction in response to current market conditions. In addition to our capital program, we paid dividends on our common stock of $2.9 billion in 2008, and repurchased $8.2 billion of our common stock.

Managing our asset portfolio. We continue to evaluate opportunities to acquire assets that will contribute to future growth at competitive prices. The 2006 Burlington Resources acquisition, the 2007 EnCana business ventures, and the 2008 Origin Energy joint venture are examples of such activity. 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. In 2008, we completed the disposition of our retail marketing assets in Norway, Sweden and Denmark, and we also sold all of our E&P properties in Argentina and the Netherlands. We closed on the sale of a large part of our U.S. retail marketing assets in January 2009.

Developing and retaining a talented work force. We strive to attract, train, develop and retain individuals with the knowledge and skills to implement our business strategy and who support our values and ethics. Throughout the company, we focus on the continued learning, development and technical training of our employees. Professional new hires participate in structured development programs designed to accelerate their technical and functional skills.

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:

Impairments. As mentioned above, we participate in capital-intensive industries. At times, our 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. We may also invest large amounts of money in exploration blocks which, if exploratory drilling proves unsuccessful, could lead to a material impairment of leasehold values. Before-tax impairments in 2008, excluding the goodwill impairment discussed below and a $7.4 billion impairment related to our LUKOIL investment, totaled $1.7 billion. This amount compares with $0.4 billion of impairments, excluding the impairment of expropriated assets (discussed below), in 2007.

Goodwill. At year-end 2008, we had $3.8 billion of goodwill on our balance sheet, compared with $29.3 billion at year-end 2007. In 2008, we recorded a $25.4 billion complete impairment of our E&P segment goodwill, primarily as a function of decreased year-end commodity prices and the decline in our market capitalization. For additional information, see Note 9 Goodwill and Intangibles, in the Notes to Consolidated Financial Statements. Deterioration of market conditions in the future could lead to other goodwill impairments that may have a substantial negative, though noncash, 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 pretax earnings within our global operations.

Fiscal and regulatory environment. As commodity prices and refining margins fluctuated upward 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. In June 2007, our Venezuelan oil projects were expropriated, and we recorded a $4.5 billion after-tax impairment (see the Expropriated Assets section of Note 10 Impairments, in the Notes to Consolidated Financial Statements). The company was also negatively impacted by increased production taxes enacted by the state of Alaska in the fourth quarter of 2007. In October 2007, the government of Ecuador increased the tax rate of the Windfall Profits Tax Law implemented in 2006, increasing the amount of government royalty entitlement on crude oil production to 99 percent of any increase in the price of crude oil above a contractual reference price. In Canada, the Alberta provincial government changed the royalty structure for Crown lands, effective January 1, 2009, so that a component of the new royalty rate is tied to prevailing prices. In October 2008, we and our co-venturers signed definitive agreements for the proportional dilution of our equity interests in the Republic of Kazakhstan s North Caspian Sea Production Sharing Agreement, which includes the Kashagan field, to allow the state-owned energy company to increase its ownership percentage effective January 1, 2008. Partially offsetting the above fiscal take increases were lower corporate income tax rates enacted by Canada and Germany during 2007. These tax rate reductions applied to all corporations and were not exclusive to the oil and gas industry.

Table of Contents

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 (WTI) were higher in 2008, compared with 2007, averaging $99.56 per barrel in 2008, an increase of 38 percent. The increase was driven by concerns during the first half of 2008 of adequate supplies given the strong oil demand growth in developing Asia and the Middle East. The average annual price for WTI moderated due to the economic crisis in the second half of 2008 that impacted demand from all regions of the world. Industry natural gas prices for Henry Hub increased 32 percent during 2008 to an average price of $9.04 per million British thermal units (MMBTU), primarily due to increased demand from the industrial and electric power sector during the first half of 2008 and higher oil prices. These factors were moderated by higher domestic production and lower demand, which led to higher storage in the second half of 2008.

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. DCP Midstream s natural gas liquids prices increased 11 percent in 2008.

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, both of which are subject to market factors over which we have no control. Industry refining margins in the United States were lower overall in comparison with 2007. The primary factor contributing to the reduced refining margins in 2008 was a decrease in gasoline demand.

The LUKOIL Investment segment consists of our investment in the ordinary shares of LUKOIL. At December 31, 2008, our ownership interest in LUKOIL was 20 percent based on issued shares and 20.06 percent based on estimated shares outstanding. LUKOIL s results are subject to factors similar to those of our E&P and R&M segments. LUKOIL s upstream results are closely linked to Russian (Urals) crude oil prices and are heavily impacted by extraction tax rates. Refining margins are significant factors on LUKOIL s downstream results. Export tariff rates for crude oil and refined products also have a significant impact on both upstream and downstream results.

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.

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 and innovation of new technologies, such as those related to conventional and nonconventional hydrocarbon recovery (including heavy oil), refining, alternative energy, biofuels and the environment. Some of these technologies have the potential to become important drivers of profitability in future years.

Table of Contents

RESULTS OF OPERATIONS

Consolidated Results

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

	Millions of Dollars		
Years Ended December 31	**2008**	2007	2006
Exploration and Production (E&P)	**$ (13,479)**	4,615	9,848
Midstream	**541**	453	476
Refining and Marketing (R&M)	**2,322**	5,923	4,481
LUKOIL Investment	**(5,488)**	1,818	1,425
Chemicals	**110**	359	492
Emerging Businesses	**30**	(8)	15
Corporate and Other	**(1,034)**	(1,269)	(1,187)
Net income (loss)	**$ (16,998)**	11,891	15,550

2008 vs. 2007

The lower results in 2008 were primarily the result of:

- A $25,443 million before- and after-tax goodwill impairment of all E&P segment goodwill. This impairment was recorded during the fourth quarter.
- A $7,410 million before- and after-tax impairment of our LUKOIL investment taken during the fourth quarter.
- Lower U.S. refining margins in our R&M segment.
- An increase in other asset impairments, predominantly in our E&P and R&M segments.

These items were partially offset by:

- Higher crude oil, natural gas and natural gas liquids prices, benefiting our E&P, Midstream and LUKOIL Investment segments. Commodity price benefits were somewhat counteracted by increased production taxes.
- A 2007 complete impairment ($4,588 million before-tax, $4,512 million after-tax) of our oil interests in Venezuela, resulting from their expropriation on June 26, 2007.

2007 vs. 2006

The lower results in 2007 were primarily the result of:

- The complete impairment of our oil interests in Venezuela.
- Lower crude oil production in the E&P segment.
- Higher production and operating expenses, higher production taxes, and higher depreciation, depletion and amortization expense in the E&P segment.

These items were partially offset by:

- The net benefit of asset rationalization efforts in the E&P and R&M segments.
- Higher realized crude oil, natural gas, and natural gas liquids prices in the E&P segment.
- Higher realized worldwide refining margins, including the benefit of planned inventory reductions, in the R&M segment.
- Increased equity earnings from our investment in LUKOIL due to higher estimated commodity prices and volumes, and an increase in our average equity ownership percentage.

Table of Contents

Statement of Operations Analysis

2008 vs. 2007

Sales and other operating revenues increased 28 percent in 2008, while purchased crude oil, natural gas and products increased 37 percent. These increases were mainly the result of higher petroleum product prices and higher prices for crude oil, natural gas and natural gas liquids.

Equity in earnings of affiliates decreased 16 percent in 2008, reflecting:

- Lower results from WRB Refining LLC, due to lower margins and a decline in equity ownership in accordance with the designed formation of the venture.
- Lower results from CPChem, due to higher operating costs, lower specialties, aromatics and styrenics margins, and lower olefins and polyolefins volumes.
- The absence of earnings from our heavy oil joint ventures expropriated by Venezuela in 2007.
- Increased losses related to our Naryanmarneftegaz (NMNG) joint venture as a result of higher production taxes and increased depreciation, depletion and amortization (DD&A) costs during the startup and early production phase of the Yuzhno Khylchuyu (YK) field.

These negative results were somewhat offset by improved results from the FCCL Oil Sands Partnership, DCP Midstream, LUKOIL (excluding the investment impairment), and CFJ Properties.

Other income decreased 45 percent during 2008, mainly due to a lower net benefit from asset rationalization efforts, the release in 2007 of escrowed funds associated with our Hamaca joint venture in Venezuela, and the settlement of retroactive adjustments for crude oil quality differentials on Trans-Alaska Pipeline System shipments (Quality Bank) in 2007.

Exploration expenses increased 33 percent during 2008, reflecting increased dry hole costs and higher expenses for post-discovery feasibility and development planning studies.

Impairments increased from $5,030 million in 2007 to $34,539 million in 2008. This increase reflects a $25,443 million goodwill impairment recorded during 2008 in our E&P segment. Also contributing to the increase was a $7,410 million impairment of our LUKOIL investment taken during 2008. These 2008 impairments were partially offset by a 2007 impairment of $4,588 million related to the expropriation of our oil interests in Venezuela. Other impairments increased $1,244 million during 2008 primarily due to property impairments taken in response to a significantly diminished outlook for crude oil and natural gas prices, refining margins and power spreads, as well as in response to revised capital spending plans. For additional information, see Note 7 Investments, Loans, and Long-Term Receivables, Note 9 Goodwill and Intangibles, and Note 10 Impairments, in the Notes to Consolidated Financial Statements.

Interest and debt expense decreased 25 percent in 2008, primarily due to lower average interest rates, as well as the absence of 2007 interest expense related to the Alaska Quality Bank settlements.

Foreign currency transaction losses incurred during 2008 totaled $117 million, compared with foreign currency transaction gains of $201 million in 2007. This change occurred as the Canadian dollar, Russian rouble, British pound, and euro all weakened against the U.S. dollar during 2008, compared with the strengthening of these currencies against the U.S. dollar in 2007.

See Note 21 Income Taxes, in the Notes to Consolidated Financial Statements, for information regarding our income tax expense and effective tax rate.

Table of Contents

2007 vs. 2006

Equity in earnings of affiliates increased 21 percent in 2007. The increase reflects earnings from WRB and FCCL, our downstream and upstream business ventures with EnCana, formed in January 2007. Also, we had improved results from LUKOIL, reflecting higher estimated commodity prices and volumes, and an increase in our average equity ownership percentage. These increases were partially offset by lower earnings from Hamaca and Petrozuata, our heavy oil joint ventures expropriated by Venezuela in the second quarter of 2007. Additionally, CPChem reported lower earnings, primarily due to lower olefins and polyolefins margins.

Other income increased 188 percent during 2007, primarily due to:

- Higher net gains on asset dispositions associated with asset rationalization efforts.
- The release in 2007 of escrowed funds related to the extinguishment of Hamaca project financing.
- The Alaska Quality Bank settlements in 2007.

These increases were partially offset by the recognition in 2006 of recoveries on business interruption insurance claims attributable to losses sustained from hurricanes in 2005.

Exploration expenses increased 21 percent during 2007, primarily reflecting the amortization of unproved North American leaseholds obtained in the Burlington Resources acquisition and the impairment of an international exploration license. The increase also reflects higher geological and geophysical expenses and higher dry hole costs.

Depreciation, depletion and amortization increased 14 percent during 2007, primarily resulting from the addition of Burlington Resources assets in the E&P segment s depreciable asset base for a full year in 2007 versus only nine months in 2006.

Impairments reflects an impairment of $4,588 million related to the expropriation of our oil interests in Venezuela recorded in the second quarter of 2007. Impairments unrelated to the expropriation decreased 35 percent during 2007, primarily due to impairments recorded in 2006 of certain assets held for sale in the R&M segment, comprised of properties, plants and equipment, trademark intangibles and goodwill.

Interest and debt expense increased 15 percent during 2007, primarily due to the interest expense component of the Alaska Quality Bank settlements, as well as higher expense associated with the funding requirements for the business venture with EnCana.

Foreign currency transaction gains during 2007 primarily reflect the strengthening of the Canadian dollar against the U.S. dollar.

Table of Contents

Segment Results
E&P

		2008	2007	2006
			Millions of Dollars	
Net Income (Loss)				
Alaska	$	**2,315**	2,255	2,347
Lower 48		**2,673**	1,993	2,001
United States		**4,988**	4,248	4,348
International		**6,976**	367	5,500
Goodwill impairment		**(25,443)**		
	$	**(13,479)**	4,615	9,848
			Dollars Per Unit	
Average Sales Prices				
Crude oil (per barrel)				
United States	$	**97.47**	68.00	61.09
International		**93.30**	70.79	63.38
Total consolidated		**95.15**	69.47	62.39
Equity affiliates*		**63.89**	45.31	46.01
Worldwide E&P		**93.12**	67.11	60.37
Natural gas (per thousand cubic feet)				
United States		**7.67**	5.98	6.11
International		**8.76**	6.51	6.27
Total consolidated		**8.28**	6.26	6.20
Equity affiliates*		**2.04**	.30	.30
Worldwide E&P		**8.27**	6.26	6.19
Natural gas liquids (per barrel)				
United States		**55.63**	46.00	40.35
International		**59.70**	48.80	42.89
Total consolidated		**57.43**	47.13	41.50
Worldwide E&P		**57.43**	47.13	41.50
Average Production Costs Per Barrel of Oil Equivalent**				
United States	$	**8.34**	6.52	5.43
International		**8.08**	7.68	5.65
Total consolidated		**8.20**	7.13	5.55
Equity affiliates*		**13.51**	8.92	5.83
Worldwide E&P		**8.37**	7.21	5.57

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

segment.

** *For information on taxes other than income taxes per barrel of oil equivalent, see the Statistics section of the supplemental Oil and Gas Operations disclosure.*

	Millions of Dollars		
Worldwide Exploration Expenses			
General and administrative; geological and geophysical; and lease rentals	$ **639**	544	483
Leasehold impairment	**273**	254	157
Dry holes	**425**	209	194
	$ **1,337**	1,007	834

41

	2008	2007	2006
	Thousands of Barrels Daily		
Operating Statistics			
Crude oil produced			
Alaska	**244**	261	263
Lower 48	**91**	102	104
United States	**335**	363	367
Europe	**214**	210	245
Asia Pacific	**91**	87	106
Canada	**25**	19	25
Middle East and Africa	**78**	81	106
Other areas	**9**	10	7
Total consolidated	**752**	770	856
Equity affiliates*			
Canada	**30**	27	
Russia and Caspian	**24**	15	15
Other areas		42	101
	806	854	972
Natural gas liquids produced			
Alaska	**17**	19	17
Lower 48	**74**	79	62
United States	**91**	98	79
Europe	**19**	14	13
Asia Pacific	**16**	14	18
Canada	**25**	27	25
Middle East and Africa	**2**	2	1
	153	155	136
	Millions of Cubic Feet Daily		
Natural gas produced**			
Alaska	**97**	110	145
Lower 48	**1,994**	2,182	2,028
United States	**2,091**	2,292	2,173
Europe	**954**	961	1,065
Asia Pacific	**609**	579	582
Canada	**1,054**	1,106	983
Middle East and Africa	**114**	125	142
Other areas	**14**	19	16

Total consolidated	**4,836**	5,082	4,961
Equity affiliates*			
Asia Pacific	**11**		
Other areas		5	9
	4,847	5,087	4,970
	Thousands of Barrels Daily		
Mining operations			
Syncrude produced	**22**	23	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, transports 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, 2008, our E&P operations were producing in the United States, Norway, the United Kingdom, Canada, Ecuador, Australia, offshore Timor-Leste in the Timor Sea, Indonesia, China, Vietnam, Libya, Nigeria, Algeria and Russia.

2008 vs. 2007

The E&P segment recorded a net loss of $13,479 million during 2008. This amount includes a $25,443 million before- and after-tax complete impairment of E&P segment goodwill. In 2007, the E&P segment had net income of $4,615 million, which includes the impact of a $4,588 million before-tax impairment ($4,512 million after-tax) related to the expropriation of our oil interests in Venezuela. For additional information, see the Goodwill Impairment section of Note 9 Goodwill and Intangibles, and the Expropriated Assets section of Note 10 Impairments, in the Notes to Consolidated Financial Statements, which are incorporated herein by reference.

The decrease in net income was attributed to the goodwill impairment, higher taxes other than income (mainly in Alaska), lower production volumes, higher operating and exploration costs, increased impairments and depreciation expense, and the absence of a 2007 benefit related to release of escrowed funds associated with our Hamaca joint venture in Venezuela. The decrease was partially offset by the absence of the 2007 Venezuela impairment, as well as higher crude oil, natural gas and natural gas liquids prices. During 2008, our E&P segment recognized property impairment charges totaling $511 million after-tax, mostly due to revised capital spending plans as a result of current project economics, as well as a significantly diminished outlook for commodity prices. A large portion of these impairments relate to fields in the U.S. Lower 48 and Canada.

E&P s results for 2008 reflect an average realized worldwide selling price of $93.12 per barrel of crude oil. In contrast, our average realized worldwide crude oil price per barrel in December 2008 was $37.23. If average crude oil prices in 2009 do not increase appreciably from the low levels at year-end 2008, we would expect E&P s 2009 results to be negatively impacted.

Proved reserves at year-end 2008 were 8.08 billion barrels of oil equivalent (BOE), compared with 8.72 billion at year-end 2007. This excludes the estimated 1,893 million BOE and 1,838 million BOE included in the LUKOIL Investment segment at year-end 2008 and 2007, respectively. Also excluded is our share of Canadian Syncrude, which was 249 million barrels at year-end 2008, compared with 221 million at year-end 2007.

U.S. E&P

Net income from our U.S. E&P operations increased 17 percent, primarily due to higher crude oil, natural gas and natural gas liquids prices. The increase was partially offset by higher production taxes (mainly in Alaska), lower volumes, an increase in impairments of properties in the Lower 48, and higher operating costs.

E&P production on a BOE basis averaged 775,000 per day in 2008, a decrease of 8 percent from 843,000 in 2007. The production decrease was primarily due to field decline and unplanned downtime in the Lower 48 reflecting the impact of hurricane disruptions.

International E&P

Net income from our international E&P operations increased from $367 million in 2007 to $6,976 million in 2008. The increase was attributed to the impact of the Venezuelan impairment on our prior-year results and higher crude oil, natural gas and natural gas liquids prices. The increase was partially offset by higher depreciation expense due to increased rates and new assets being placed in service, increased taxes other than income, higher operating costs, and the absence of a 2007 benefit related to release of escrowed funds associated with our Hamaca joint venture in Venezuela.

International E&P production averaged 992,000 BOE per day in 2008, a decrease of 2 percent from 1,014,000 in 2007. Decreases in production were caused by field decline and the expropriation of our Venezuelan oil interests. These decreases were mostly offset by increased production from new developments

Table of Contents

in the United Kingdom, Indonesia, Russia, Norway and Canada. Our Syncrude mining operations produced 22,000 barrels per day in 2008, compared with 23,000 barrels per day in 2007.

In regards to our Venezuelan assets expropriated during 2007, we filed a request for international arbitration on November 2, 2007, with the International Centre for Settlement of Investment Disputes (ICSID), an arm of the World Bank. The request was registered by ICSID on December 13, 2007. The tribunal of three arbitrators is constituted, and the arbitration proceeding is under way.

In October 2007, the government of Ecuador increased the tax rate of the Windfall Profits Tax Law implemented in 2006, increasing the amount of government royalty entitlement on crude oil production to 99 percent of any increase in the price of crude oil above a contractual reference price. In April 2008, we initiated arbitration with ICSID against The Republic of Ecuador and PetroEcuador as a result of the government s confiscatory fiscal measures enacted in 2006 and 2007, as well as the government-mandated renegotiation of our production sharing contracts into service agreements with inferior fiscal and legal terms. The arbitration has been registered by ICSID, the arbitration tribunal is fully constituted and the case is proceeding.

In Canada, the Alberta provincial government changed the royalty structure for Crown lands, effective January 1, 2009. A component of the new royalty rate calculation for each well will be based on prevailing prices, and therefore we expect that our reported production and reserve volumes will move inversely with changes in commodity prices. This change will impact both our conventional western Canada natural gas and oil business and our oil sands operations.

2007 vs. 2006

Net income from the E&P segment decreased 53 percent in 2007. In the second quarter of 2007, we recorded a noncash impairment of $4,588 million before-tax ($4,512 million after-tax) related to the expropriation of our oil interests in Venezuela. The decrease in net income during 2007 reflects this impairment, as well as lower crude oil production, higher production taxes and operating costs, and higher DD&A expense. These decreases were partially offset by:

- Higher realized crude oil, natural gas liquids and natural gas prices.
- A net benefit from asset rationalization efforts.
- A benefit related to the release of escrowed funds in connection with the extinguishment of the Hamaca project financing.
- The Alaska Quality Bank settlements.

Proved reserves at year-end 2007 were 8.72 billion BOE, compared with 9.36 billion at year-end 2006. This excludes the estimated 1,838 million BOE and 1,805 million BOE included in the LUKOIL Investment segment at year-end 2007 and 2006, respectively. Also excluded is our share of Canadian Syncrude, which was 221 million barrels at year-end 2007, compared with 243 million at year-end 2006.

U.S. E&P

Net income from our U.S. E&P operations decreased 2 percent, primarily due to higher production taxes in Alaska, higher operating costs and DD&A expense, and lower crude oil production. These decreases were mostly offset by:

- Higher crude oil and natural gas liquids prices, and higher natural gas and natural gas liquids production.
- The Alaska Quality Bank settlements.
- Gains on the sale of assets in Alaska and the Gulf of Mexico.

In December 2007, the state of Alaska enacted new production tax legislation, with retroactive provisions, which results in a higher production tax structure for ConocoPhillips.

Table of Contents

U.S. E&P production averaged 843,000 BOE per day in 2007, an increase of 4 percent from 808,000 in 2006. Production was impacted by the inclusion of the Burlington Resources assets for the full year of 2007, offset slightly by field decline.

International E&P

Net income from our international E&P operations decreased 93 percent, primarily due to the impairment of expropriated assets in Venezuela, lower crude oil production, higher DD&A expense, and higher operating costs. These decreases were partially offset by higher crude oil and natural gas prices, a net benefit from asset rationalization efforts, and the benefit from the release of the escrowed funds related to the Hamaca project. International E&P production averaged 1,014,000 BOE per day in 2007, a decrease of 10 percent from 1,128,000 in 2006. Production was impacted by the expropriation of our Venezuelan oil projects, planned and unplanned downtime in Australia and the North Sea, production sharing contract impacts in Australia, our exit from Dubai, and the effect of asset dispositions. These decreases were slightly offset by new production volumes from our FCCL upstream business venture with EnCana, as well as inclusion of the Burlington Resources assets for the full year of 2007. Our Syncrude mining operations produced 23,000 barrels per day in 2007, compared with 21,000 in 2006.

During 2006, significant tax legislation was enacted in the United Kingdom and in Canada. The United Kingdom increased income tax rates on upstream income, resulting in a negative earnings impact of $470 million to adjust 2006 taxes and restate deferred tax liabilities. In Canada, an overall rate reduction in 2006 resulted in a favorable earnings impact of $401 million to restate deferred tax liabilities.

Midstream

		2008	2007	2006
			Millions of Dollars	
Net Income*	**$**	**541**	453	476
* *Includes DCP Midstream-related net income:*	*$*	***458***	*336*	*385*
			Dollars Per Barrel	
Average Sales Prices				
U.S. natural gas liquids*				
Consolidated	**$**	**56.29**	47.93	40.22
Equity affiliates		**52.08**	46.80	39.45

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

	Thousands of Barrels Daily
Operating Statistics	

Natural gas liquids extracted*	**188**	211	209
Natural gas liquids fractionated**	**165**	173	144

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

** *Excludes DCP Midstream.*

The Midstream segment purchases raw natural gas from producers and gathers natural gas through an extensive network of pipeline gathering systems. The natural gas is then processed to extract natural gas liquids from the raw gas stream. The remaining residue gas is marketed to electrical utilities, industrial users, and gas marketing companies. Most of the natural gas liquids are fractionated separated into individual components like ethane, butane and propane and marketed as chemical feedstock, fuel or blendstock. The Midstream segment consists of our 50 percent equity investment in DCP Midstream, 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.

Table of Contents

2008 vs. 2007

Net income from the Midstream segment increased 19 percent in 2008. The increase was primarily due to higher realized natural gas liquids prices, partially offset by higher operating costs and higher depreciation expense.

2007 vs. 2006

Net income from the Midstream segment decreased 5 percent in 2007, reflecting a shift in natural gas purchase contract terms that are more favorable to natural gas producers. In addition, earnings from DCP Midstream were lower, primarily due to increased operating costs, mainly repairs, maintenance and asset integrity work. The results also reflect a positive tax adjustment included in the 2006 results. These decreases were partially offset by higher natural gas liquids prices.

Table of Contents

R&M

	2008	2007	2006
	Millions of Dollars		
Net Income			
United States	$ **1,540**	4,615	3,915
International	**782**	1,308	566
	$ **2,322**	5,923	4,481
	Dollars Per Gallon		
U.S. Average Sales Prices*			
Gasoline			
Wholesale	$ **2.65**	2.27	2.04
Retail	**2.81**	2.42	2.18
Distillates wholesale	**3.06**	2.29	2.11

* *Excludes excise taxes.*

	2008	2007	2006
	Thousands of Barrels Daily		
Operating Statistics			
Refining operations*			
United States			
Crude oil capacity**	**2,008**	2,035	2,208
Crude oil runs	**1,849**	1,944	2,025
Capacity utilization (percent)	**92%**	96	92
Refinery production	**2,035**	2,146	2,213
International			
Crude oil capacity**	**670**	687	651
Crude oil runs	**567**	616	591
Capacity utilization (percent)	**85%**	90	91
Refinery production	**575**	633	618
Worldwide			
Crude oil capacity**	**2,678**	2,722	2,859
Crude oil runs	**2,416**	2,560	2,616
Capacity utilization (percent)	**90%**	94	92
Refinery production	**2,610**	2,779	2,831
Petroleum products sales volumes			
United States			
Gasoline	**1,128**	1,244	1,336
Distillates	**893**	872	850
Other products	**374**	432	531
	2,395	2,548	2,717
International	**645**	697	759

	3,040	3,245	3,476

* *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 periods. Actual capacity at year-end 2007 and 2006 was 2,037,000 and 2,208,000 barrels per day, respectively, for our domestic refineries, and 669,000 and 693,000 barrels per day, respectively, for our international refineries.*

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 mainly in the United States, Europe and the Asia Pacific region.

2008 vs. 2007

Net income from the R&M segment decreased 61 percent in 2008. The results were lower due to decreases in U.S. refining margins and volumes, increased property impairments, higher operating costs, a reduced benefit from asset rationalization efforts, and lower international marketing and refining volumes due to asset sales. During 2008, our R&M segment had property impairments totaling $511 million after-tax, mostly due to a significantly diminished outlook for refining margins. These R&M decreases were partially offset by higher international marketing margins.

During 2008, our worldwide refining capacity utilization rate was 90 percent, compared with 94 percent in 2007. We expect our 2009 rate to be similar to our rate in 2008.

U.S. R&M

Net income from our U.S. R&M operations decreased 67 percent in 2008. The decrease was primarily the result of lower refining margins and, to a lesser extent, lower refining volumes and higher turnaround and utility costs. In addition, property impairments increased in 2008, including an impairment related to one of our U.S. refineries.

Our U.S. refining capacity utilization rate was 92 percent in 2008, compared with 96 percent in 2007. The decline in the current-year rate resulted mainly from refinery optimization and unplanned downtime including impacts from hurricanes on our U.S. Gulf Coast refineries.

International R&M

Net income from our international R&M operations decreased 40 percent in 2008. Contributing to the decrease were higher property impairments, including impacts from a 2008 impairment of a refinery in Europe and the absence of a 2007 benefit related to an increase in the fair value of previously impaired assets held for sale. Net income for 2008 was also impacted by a reduced net benefit from asset rationalization efforts, negative foreign currency exchange impacts, the absence of a $141 million 2007 German tax legislation benefit, and lower refining and marketing volumes due to asset sales. Higher international refining and marketing margins partially offset these decreases.

Our international refining capacity utilization rate was 85 percent in 2008, compared with 90 percent during the previous year. The utilization rate was primarily impacted by reduced crude throughput at our Wilhelmshaven refinery due to economic conditions and planned maintenance.

2007 vs. 2006

Net income from the R&M segment increased 32 percent in 2007. The increase resulted primarily from:

- The net benefit of asset rationalization efforts.
- Higher realized worldwide refining margins, reflecting in part the impact of planned inventory reductions, including a benefit of $260 million from the liquidation of prior-year layers under the last-in, first-out (LIFO) method.
- Higher U.S. Gulf and East Coast refining volumes due to lower planned maintenance and less weather-related downtime.
- A 2007 deferred tax benefit related to tax legislation in Germany.

These increases were partially offset by the net impact of our contribution of assets to WRB Refining LLC, foreign currency impacts, and lower marketing sales volumes due to asset sales.

U.S. R&M

Net income from our U.S. R&M operations increased 18 percent in 2007, primarily due to:

- Higher refining volumes at our Gulf and East Coast refineries.
- Higher realized refining and marketing margins, due in part to the benefit of planned inventory reductions.

Table of Contents

These items were partially offset by the net impact of our contribution of the Wood River and Borger refineries to WRB, and the impact of business interruption insurance recoveries on our 2006 results. Our U.S. refining capacity utilization rate was 96 percent in 2007, compared with 92 percent in 2006, primarily reflecting lower planned maintenance and less weather-related downtime.

International R&M

Net income from our international R&M operations increased 131 percent in 2007, due primarily to:

- The net benefit of asset rationalization efforts.
- The deferred tax benefit related to the tax legislation in Germany.
- Higher realized refining margins.

These increases were partially offset by foreign currency impacts and lower marketing volumes due to the asset sales. Our international refining capacity utilization rate was 90 percent in 2007, compared with 91 percent in 2006. The 2007 utilization rate was affected by a temporary idling of the Wilhelmshaven refinery in Germany during the month of August due to economic conditions.

LUKOIL Investment

	Millions of Dollars		
	2008	2007	2006
Net Income (Loss)	**$ (5,488)**	1,818	1,425
Operating Statistics*			
Crude oil production (thousands of barrels daily)	**386**	401	360
Natural gas production (millions of cubic feet daily)	**356**	256	244
Refinery crude oil processed (thousands of barrels daily)	**229**	214	179

* *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. At December 31, 2008, our ownership interest in LUKOIL was 20 percent based on authorized and issued shares. Our ownership interest based on estimated shares outstanding, used for equity method accounting, was 20.06 percent at that date.

Because LUKOIL s accounting cycle close and preparation of U.S. generally accepted accounting principles financial statements occur subsequent to our reporting deadline, our equity earnings and statistics for our LUKOIL investment are estimated based on current market indicators, publicly available LUKOIL information, 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. In addition to our estimated 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 book value of our investment. The segment also includes the costs associated with our employees seconded to LUKOIL.

Table of Contents

2008 vs. 2007

The LUKOIL Investment segment had a $5,488 million net loss during 2008, compared with $1,818 million of net income in 2007. The 2008 results include a $7,410 million noncash, before- and after-tax impairment of our LUKOIL investment taken during the fourth quarter. For additional information, see the LUKOIL section of Note 7 Investments, Loans and Long-Term Receivables, in the Notes to Consolidated Financial Statements, which is incorporated herein by reference.

Excluding the impact of the impairment, income from the LUKOIL Investment segment increased 6 percent in 2008. This increase was primarily due to higher estimated realized prices of both refined product and crude oil sales. Partially offsetting these positive impacts were higher estimated extraction taxes and higher estimated crude and refined product export tariff rates, as well as higher estimated operating costs and lower estimated crude volumes. The adjustment to estimated results for the fourth quarter of 2007, recorded in 2008, decreased net income $16 million, compared with a $19 million decrease to net income recorded in 2007 to adjust the estimated results for the fourth quarter of 2006.

2007 vs. 2006

Net income from the LUKOIL Investment segment increased 28 percent during 2007, primarily due to higher estimated realized prices, higher estimated volumes, and an increase in our average equity ownership. The increase was partially offset by higher estimated taxes and operating costs, as well as the net impact from the alignment of estimated net income to reported results. The adjustment to estimated results for the fourth quarter of 2006, recorded in 2007, decreased net income $19 million, compared with a $71 million increase to net income recorded in 2006 to adjust the estimated results for the fourth quarter of 2005.

Chemicals

	Millions of Dollars		
	2008	2007	2006
Net Income	**$ 110**	359	492

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.

2008 vs. 2007

Net income from the Chemicals segment decreased 69 percent in 2008 due to higher utilities and other operating costs, the absence of 2007 one-time tax benefits, lower specialties, aromatics and styrenics margins, and lower olefins and polyolefins volumes. Increases in olefins and polyolefins margins somewhat offset these negative effects. Business conditions in the chemicals and plastics industry are expected to remain challenging in the near term.

2007 vs. 2006

Net income from the Chemicals segment decreased 27 percent during 2007, primarily due to lower olefins and polyolefins margins and higher turnaround and weather-related repair costs, offset partially by a capital-loss tax benefit of $65 million recorded in the fourth quarter of 2007.

Table of Contents

Emerging Businesses

		Millions of Dollars	
	2008	2007	2006
Net Income (Loss)			
Power	$ **106**	53	82
Other	**(76)**	(61)	(67)
	$ **30**	(8)	15

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 and innovation of new technologies, such as those related to conventional and nonconventional hydrocarbon recovery (including heavy oil), refining, alternative energy, biofuels, and the environment.

2008 vs. 2007

Emerging Businesses reported net income of $30 million in 2008, compared with a net loss of $8 million in 2007. The increase primarily reflects improved international power generation results, including the impact of higher spark spreads. These benefits were partially offset by an $85 million after-tax impairment of a U.S. cogeneration power plant, as well as by lower domestic power results.

2007 vs. 2006

The Emerging Businesses segment had a net loss of $8 million in 2007, compared with net income of $15 million in 2006. The decrease reflects lower margins from the Immingham power plant in the United Kingdom, as well as higher spending associated with alternative energy programs. These decreases were slightly offset by the inclusion of a write-down of a damaged gas turbine at a domestic power plant in 2006 results.

Corporate and Other

		Millions of Dollars	
	2008	2007	2006
Net Loss			
Net interest	$ **(558)**	(820)	(870)
Corporate general and administrative expenses	**(202)**	(176)	(133)
Acquisition/merger-related costs		(44)	(98)
Other	**(274)**	(229)	(86)
	$ **(1,034)**	(1,269)	(1,187)

2008 vs. 2007

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. In 2008, net interest decreased 32 percent primarily due to lower average interest rates and a higher effective tax rate. Corporate general and administrative expenses increased 15 percent in 2008, mainly as a result of increased charitable contributions. Acquisition-related costs in 2007 included transition costs associated with the Burlington Resources acquisition. The category Other includes certain foreign currency transaction gains and losses, environmental costs associated with sites no longer in operation, and other costs not directly associated with an operating segment. Other expenses increased in 2008 due to various tax-related adjustments, partially offset by lower foreign currency losses.

Table of Contents

2007 vs. 2006

Net interest decreased 6 percent in 2007, primarily due to higher amounts of interest being capitalized, partially offset by a premium on the early retirement of debt. Corporate general and administrative expenses increased 32 percent in 2007, primarily due to higher benefit-related expenses. Acquisition-related costs in 2007 included transition costs associated with the Burlington Resources acquisition. Results from Other were primarily impacted by foreign currency losses in 2007.

CAPITAL RESOURCES AND LIQUIDITY

Financial Indicators

	Millions of Dollars Except as Indicated		
	2008	2007	2006
Net cash provided by operating activities	$ **22,658**	24,550	21,516
Short-term debt	**370**	1,398	4,043
Total debt	**27,455**	21,687	27,134
Minority interests	**1,100**	1,173	1,202
Common stockholders equity	**55,165**	88,983	82,646
Percent of total debt to capital*	**33%**	19	24
Percent of floating-rate debt to total debt	**37**	25	41

* *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. Cash generated from operating activities is the primary source of funding. In addition, during 2008 we raised $1,640 million in proceeds from asset dispositions. During 2008, available cash was used to support our ongoing capital expenditures and investments program, repurchase shares of our common stock, provide loan financing to certain equity affiliates, pay dividends, and meet the funding requirements to FCCL Oil Sands Partnership. Total dividends paid on our common stock during the year were $2,854 million. During 2008, cash and cash equivalents decreased $701 million to $755 million.

In addition to cash flows from operating activities and proceeds from asset sales, we rely on our commercial paper and credit facility programs, and our shelf registration statements to support our short- and long-term liquidity requirements. The credit markets, including the commercial paper markets in the United States, have recently experienced adverse conditions. Although we have not been materially impacted by these conditions, continuing volatility in the credit markets may increase costs associated with issuing commercial paper or other debt instruments due to increased spreads over relevant interest rate benchmarks. Such volatility may also affect our ability, or the ability of third parties with whom we seek to do business, to access those credit markets. Notwithstanding these adverse market conditions, we believe current cash and short-term investment balances and cash generated by operations, together with access to external sources of funds as described below in the Significant Sources of Capital section, will be sufficient to meet our funding requirements in the near- and long-term, including our capital spending program, dividend payments, required debt payments and the funding requirements to FCCL.

Significant Sources of Capital

Operating Activities

During 2008, cash of $22,658 million was provided by operating activities, an 8 percent decrease from cash from operations of $24,550 million in 2007. Contributing to the decrease were lower U.S. refining margins and volumetric inventory builds in our R&M segment in 2008, versus reductions in 2007. These factors were partially offset by higher commodity prices in our E&P segment.

During 2007, cash flow from operations increased $3,034 million to $24,550 million. Contributing to the improvement over 2006 results was a planned inventory reduction in the 2007 period, partially related to the formation of the WRB downstream business venture; the impact of the Burlington Resources acquisition late in the first quarter of 2006; and higher worldwide crude oil prices in 2007. These positive factors were partially offset by the absence of dividends from our Venezuelan operations in 2007.

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 2008 and 2007, we benefited from favorable crude oil and natural gas prices, although these prices deteriorated significantly in the fourth quarter of 2008. Prices and margins are 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, production levels can cause variability in cash flows, although historically this variability has not been as significant as that caused by commodity prices.

Our production for 2008, including our share of production from equity affiliates, averaged 2.21 million BOE per day. Future production is subject to numerous uncertainties, including, among others, the volatile crude oil and natural gas price environment, which may impact project investment decisions; the price effect of production sharing contracts; changes in fiscal terms of projects; project delays; and weather-related disruptions. Although actual year-to-year production levels will vary, based on our current outlook and planning assumptions, we project no material change in annual production levels from 2008 through 2013.

To maintain or grow our production volumes, we must continue to add to our proved reserve base. Our reserve replacement in 2008, including equity affiliates, was 31 percent. The 2008 reserve replacement was adversely impacted by low year-end commodity prices, which resulted in significant negative reserve revisions. Our 2008 reserve replacement from consolidated operations and from our equity affiliates was a negative 23 percent and a positive 224 percent, respectively. Over the three-year period ending December 31, 2008, our reserve replacement was 124 percent. This was comprised of a reserve replacement from consolidated operations of 115 percent and from equity affiliates of 153 percent. The purchase of reserves in place was a significant factor in replacing our reserves over the past three-year period, partially offset by the expropriation of our Venezuelan oil assets. Significant purchases during this three-year period included reserves added as part of the 2008 Origin Energy joint venture, the 2007 EnCana business venture, and the 2006 acquisition of Burlington Resources, as well as proved reserves added through our investments in LUKOIL in 2006. The reserve replacement amounts above were based on the sum of our net additions (revisions, improved recovery, purchases, extensions and discoveries, and sales) divided by our production, as shown in our reserve table disclosures in the Oil and Gas Operations section of this report.

We are developing and pursuing projects we anticipate will allow us to add to our reserve base. 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 the Critical Accounting Estimates section, 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 reservoirs. In 2008 and 2006, revisions decreased our reserves, while in 2007 revisions increased reserves. It is not possible to reliably predict how

53

revisions will impact reserve quantities in the future. See the Capital Spending section for an 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 caused by refining margins.

In 2006, we received approximately $1.1 billion in distributions from two heavy-oil projects in Venezuela. The majority of these distributions represented operating results from previous years. We did not receive an operating distribution related to these projects in 2007 or 2008.

Asset Sales

Proceeds from asset sales in 2008 were $1,640 million, compared with $3,572 million in 2007. The amounts for both periods are mainly due to asset rationalization efforts related to the program we announced in April 2006 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 do not expect any material asset dispositions in 2009 beyond the sale of our U.S. retail marketing assets. In January 2009, we closed on the sale of a large part of these assets, which included seller financing in the form of a $370 million five-year note and letters of credit totaling $54 million.

Commercial Paper and Credit Facilities

At December 31, 2008, we had two revolving credit facilities totaling $9.85 billion, consisting of a $7.35 billion facility, expiring in September 2012, and a $2.5 billion facility scheduled to expire in September 2009 (terminated in early 2009, see the Shelf Registrations section below). The $7.35 billion facility was reduced from $7.5 billion during the third quarter of 2008 due to the bankruptcy of Lehman Commercial Paper Inc., one of the revolver participants. The $2.5 billion facility is a 364-day bank facility entered into during October 2008 to provide additional support of a temporary expansion of our commercial paper program. We expanded our commercial paper program to ensure adequate liquidity after the initial funding of our transaction with Origin Energy. For additional information on the Origin transaction, see Note 7 Investments, Loans and Long-Term Receivables, in the Notes to Consolidated Financial Statements.

Our revolving credit facilities may be used as direct bank borrowings, as support for issuances of letters of credit totaling up to $750 million, as support for our commercial paper programs, or as support of up to $250 million on commercial paper issued by TransCanada Keystone Pipeline LP, a Keystone pipeline joint venture entity. The revolving credit 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 facility 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 ConocoPhillips, or by any of its consolidated subsidiaries.

Our primary funding source for short-term working capital needs is the ConocoPhillips $8.1 billion commercial paper program. Commercial paper maturities are generally limited to 90 days. We also have the ConocoPhillips Qatar Funding Ltd. $1.5 billion commercial paper program, which is used to fund commitments relating to the Qatargas 3 project. At December 31, 2008 and 2007, we had no direct outstanding borrowings under the revolving credit facilities, but $40 million and $41 million, respectively, in letters of credit had been issued. In addition, under both commercial paper programs, there was $6,933 million of commercial paper outstanding at December 31, 2008, compared with $725 million at December 31, 2007. Since we had $6,933 million of commercial paper outstanding, had issued $40 million of letters of credit and had up to a $250 million guarantee on commercial paper issued by Keystone, we had access to $2.6 billion in borrowing capacity under our revolving credit facilities at December 31, 2008.

Shelf Registrations

We have a universal shelf registration statement on file with the U.S. Securities and Exchange Commission (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. Under this shelf registration, in May 2008 we issued notes consisting of $400 million of 4.40% Notes due 2013, $500 million of 5.20% Notes due 2018 and

Table of Contents

$600 million of 5.90% Notes due 2038. The proceeds from the offering were used at that time to reduce commercial paper and for general corporate purposes.

Also under this shelf registration, in early 2009 we issued $1.5 billion of 4.75% Notes due 2014, $2.25 billion of 5.75% Notes due 2019, and $2.25 billion of 6.50% Notes due 2039. The proceeds of the notes were primarily used to reduce outstanding commercial paper balances. Under the terms of the $2.5 billion, 364-day revolving credit facility noted above, the receipt of the proceeds from this bond offering terminated this revolving credit facility.

Our senior long-term debt is rated A1 by Moody s Investor Service and A by both Standard and Poors Rating Service and Fitch, unchanged from December 31, 2008. We do not have any ratings triggers on any of our corporate debt that would cause an automatic default, and thereby impact our access to liquidity, in the event of a downgrade of our credit rating. In the event our credit rating deteriorates to a level prohibiting us from accessing the commercial paper market, we would still be able to access funds under our $7.35 billion revolving credit facility.

We also have on file with the SEC a shelf registration statement 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.

Minority Interests

At December 31, 2008, we had outstanding $1,100 million of equity in less than wholly owned consolidated subsidiaries held by minority interest owners, including a minority interest of $507 million in Ashford Energy Capital S.A. The remaining minority interest amounts are primarily related to operating joint ventures we control. The largest of these, amounting to $580 million, was related to Darwin LNG, an operation located in Australia s Northern Territory.

In December 2001, in order to raise funds for general corporate purposes, ConocoPhillips and Cold Spring Finance S.a.r.l. 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 consisting of 1.32 percent plus a three-month LIBOR rate set at the beginning of each quarter. The preferred return at December 31, 2008, was 5.37 percent. In 2008, Cold Spring declined its option to remarket its investment in Ashford. This option remains available in 2018 and at each 10-year anniversary thereafter. If remarketing is unsuccessful, we could be required to provide a letter of credit in support of Cold Spring s investment, or in the event such a letter of credit is not provided, cause the redemption of Cold Spring s investment in Ashford. Should our credit rating fall below investment grade, Ashford would require a letter of credit to support $475 million of the term loans, as of December 31, 2008, 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, 2008, Ashford held $2.0 billion of ConocoPhillips subsidiary notes and $28 million in investments unrelated to ConocoPhillips. We report Cold Spring s investment as a minority interest because it is not mandatorily redeemable, and the entity does not have a specified liquidation date. Other than the obligation to make payment on the subsidiary notes described above, Cold Spring does not have recourse to our general credit.

Off-Balance Sheet Arrangements

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, 2008, we were liable for certain contingent obligations under the following contractual arrangements:

- *Qatargas 3:* We own a 30 percent interest in Qatargas 3, an integrated project to produce and liquefy natural gas from Qatar s North field. The other participants in the project are affiliates of Qatar Petroleum (68.5 percent) and Mitsui & Co., Ltd. (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, currently expected in 2011, all project loan facilities, including the ConocoPhillips loan facilities, will become nonrecourse to the project participants. At December 31, 2008, Qatargas 3 had $3.0 billion outstanding under all the loan facilities, of which ConocoPhillips provided $835 million, and an additional $76 million of accrued interest.

Rockies Express Pipeline LLC: In June 2006, we issued a guarantee for 24 percent of $2.0 billion in credit facilities issued to Rockies Express Pipeline LLC. Rockies Express is constructing 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 facilities are fully utilized and Rockies Express fails to meet its obligations under the credit agreement. At December 31, 2008, Rockies Express had $1,561 million outstanding under the credit facilities, with our 24 percent guarantee equaling $375 million. In addition, we have a 24 percent guarantee on $600 million of Floating Rate Notes due 2009. It is anticipated that construction completion will be achieved in 2009, and refinancing will take place at that time, making the debt nonrecourse.

Keystone Oil Pipeline: In December 2007, we acquired a 50 percent equity interest in four Keystone pipeline entities (Keystone), to create a joint venture with TransCanada Corporation. Keystone is constructing a crude oil pipeline originating in Alberta, with delivery points in Illinois and Oklahoma. In connection with certain planning and construction activities, we agreed to reimburse TransCanada with respect to a portion of guarantees issued by TransCanada for certain of Keystone s obligations to third parties. Our maximum potential amount of future payments associated with these guarantees is based on our ultimate ownership percentage in Keystone and is estimated to be $180 million, which could become payable if Keystone fails to meet its obligations and the obligations cannot otherwise be mitigated. Payments under the guarantees are contingent upon the partners not making necessary equity contributions into Keystone; therefore, it is considered unlikely payments would be required. All but $8 million of the guarantees will terminate after construction is completed, currently estimated to occur in 2010.

In October 2008, we elected to exercise an option to reduce our equity interest in Keystone from 50 percent to 20.01 percent. The change in equity will occur through a dilution mechanism, which is expected to gradually lower our ownership interest until it reaches 20.01 percent by the third quarter of 2009. At December 31, 2008, our ownership interest was 38.7 percent.

In addition to the above guarantees, in order to obtain long-term shipping commitments that would enable a pipeline expansion starting at Hardisty, Alberta, and extending to near Port Arthur, Texas, the Keystone owners executed an agreement in July 2008 to guarantee Keystone s obligations under its agreement to provide transportation at a specified price for certain shippers to the Gulf Coast. Although our guarantee is for 50 percent of these obligations, TransCanada has agreed to reimburse us for amounts we pay in excess of our ownership percentage in Keystone. Our maximum potential amount of future payments, or cost of volume delivery, under this guarantee, after such reimbursement, is estimated to be $220 million ($550 million before reimbursement) based on a full 20-year term of the shipping commitments, which could become payable if Keystone fails to meet its obligations under the agreements and the obligations cannot otherwise be mitigated. Future payments are considered unlikely, as the payments, or cost of volume delivery, are contingent upon Keystone defaulting on its obligation to construct the pipeline in accordance with the terms of the agreement.

In December 2008, we provided a guarantee of up to $250 million of balances outstanding under a commercial paper program. This program was established by Keystone to provide funding for a portion of Keystone s construction costs attributable to our ownership interest in the project. Payment under the guarantee would be due in the event Keystone failed to repay principal and interest, when due, to short-term noteholders. The commercial paper program and our guarantee are expected to increase as funding needs increase during construction of the Keystone pipeline. Keystone s other owner will guarantee a similar, but separate, funding vehicle. Post-construction Keystone financing is anticipated to be nonrecourse to us. At December 31, 2008, $200 million was outstanding under the Keystone commercial paper program guaranteed by us.

For additional information about guarantees, see Note 14 Guarantees, in the Notes to Consolidated Financial Statements, which is incorporated herein by reference.

Capital Requirements

Our debt balance at December 31, 2008, was $27.5 billion, an increase of $5.8 billion during 2008, and our debt-to-capital ratio was 33 percent at year-end 2008, versus 19 percent at the end of 2007. The increase in the debt-to-capital ratio was mainly due to noncash impairments taken in the fourth quarter of 2008 and the increase in debt. Our debt-to-capital target range is 20 percent to 25 percent.

In January 2008, we reduced our Floating Rate Five-Year Term Note due 2011 from $3 billion to $2 billion, with a subsequent reduction in June 2008 to $1.5 billion. In March 2008, we redeemed our $300 million 7.125% Debentures due 2028 at a premium of $8 million, plus accrued interest.

On January 3, 2007, we closed on a business venture with EnCana. As part of this transaction, we are obligated to contribute $7.5 billion, plus accrued interest, over a 10-year period, beginning in 2007, to the upstream business venture, FCCL, formed as a result of the transaction. An initial contribution of $188 million was made upon closing in January. Quarterly principal and interest payments of $237 million began in the second quarter of 2007, and will continue until the balance is paid. Of the principal obligation amount, approximately $625 million is short-term and was included in the Accounts payable related parties line on our December 31, 2008, consolidated balance sheet. The principal portion of these payments, which totaled $593 million in 2008, was included in the Other line in the financing activities section of our consolidated statement of cash flows. Interest accrues at a fixed annual rate of 5.3 percent on the unpaid principal balance. Fifty percent of the quarterly interest payments was reflected as an additional capital contribution and was included in the Capital expenditures and investments line on our consolidated statement of cash flows.

On July 9, 2007, we announced plans to repurchase up to $15 billion of our common stock through the end of 2008. This amount included $2 billion remaining under a previously announced program. At year-end 2007, approximately $10.1 billion remained authorized for share repurchases in 2008. During 2008, we repurchased 103.7 million shares of our common stock at a cost of $8.2 billion.

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, 2008, we had provided $835 million in loan financing, and an additional $76 million of accrued interest.

In 2004, we finalized our transaction with Freeport LNG Development, L.P. to participate in an LNG receiving terminal in Quintana, Texas, for which 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 to provide loan financing for the construction of the facility. The terminal became operational in June 2008, and in August 2008, the loan was converted from a construction loan to a term loan and consisted of $650 million in loan financing and $124 million of accrued interest. Freeport began making repayments in September 2008, and the loan balance outstanding at December 31, 2008, was $757 million.

In 2004, ConocoPhillips and LUKOIL agreed to the expansion of the Varandey terminal as part of our investment in the OOO Naryanmarneftegaz (NMNG) joint venture. 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. Terminal construction was completed in June 2008, and the final loan amount was $275 million at December 2008 exchange rates, excluding accrued interest. Although repayments are not required to start until May 2010, Varandey used available cash to repay $12 million of interest in the second half of 2008. The outstanding accrued interest at December 31, 2008, was $38 million at December exchange rates.

Our loans to Qatargas 3, Freeport and Varandey Terminal Company are included in the Loans and advances related parties line on our consolidated balance sheet, while the short-term portion is in Accounts and notes receivable related parties.

In February 2009, we announced a quarterly dividend of 47 cents per share. The dividend is payable March 2, 2009, to stockholders of record at the close of business February 23, 2009.

Contractual Obligations

The following table summarizes our aggregate contractual fixed and variable obligations as of December 31, 2008:

		Millions of Dollars Payments Due by Period			
	Total	Up to 1 Year	Year 2-3	Year 4-5	After 5 Years
Debt obligations (a)	$ 27,427	353	6,205	9,511	11,358
Capital lease obligations	28	17	5		6
Total debt	27,455	370	6,210	9,511	11,364
Interest on debt and other obligations	14,846	1,381	2,403	1,640	9,422
Operating lease obligations	3,769	868	1,257	727	917
Purchase obligations (b)	76,862	30,575	8,415	5,726	32,146
Joint venture acquisition obligation (c)	6,294	625	1,354	1,505	2,810
Other long-term liabilities (d)					
Asset retirement obligations	6,615	258	543	604	5,210
Accrued environmental costs	979	173	288	146	372
Unrecognized tax benefits (e)	100	100	(e)	(e)	(e)
Total	$ 136,920	34,350	20,470	19,859	62,241

(a) Includes $639 million of net unamortized premiums and discounts. See Note 12 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. Does not include purchase commitments for jointly owned fields and facilities where we are not the operator.

The majority of the purchase obligations are market-based contracts, including exchanges and futures, for the purchase of products such as crude oil, unfractionated natural gas liquids (NGL), natural gas, and power. The products are mostly used to supply our refineries and fractionators, optimize the supply chain, and resell to customers. Product purchase commitments with third parties totaled $35,732 million; $28,315 million of these commitments are product purchases from the following affiliated companies: CPChem, mostly for natural gas and NGL over the remaining term of 91 years, and Excel Paralubes, for base oil over the remaining initial term of 16 years.

Purchase obligations of $8,185 million are related to agreements to access and utilize the capacity of third-party equipment and facilities, including pipelines and LNG and product terminals, to transport, process, treat, and store products.

The remainder is primarily our net share of purchase commitments for materials and services for jointly owned fields and facilities where we are the operator.

(c) Represents the remaining amount of contributions, excluding interest, due over an eight-year period to the FCCL upstream joint venture formed with EnCana.

(d) Does not include: Pensions for the 2009 through 2013 time period, we expect to contribute an average of $625 million per year to our qualified and nonqualified pension and postretirement benefit plans in the United States and an average of $161 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 $925 million for 2009 and then approximately $550 million per year for the remaining four years. Our required minimum funding in 2009 is expected to be $274 million in the United States and $98 million outside the United States.

(e) Excludes unrecognized

tax benefits of $968 million because the ultimate disposition and timing of any payments to be made with regard to such amount are not reasonably estimable. Although unrecognized tax benefits are not a contractual obligation, they are presented in this table because they represent potential demands on our liquidity.

Capital Spending

Capital Expenditures and Investments

	Millions of Dollars			
	2009 Budget	**2008**	2007	2006
E&P				
United States Alaska	$ 832	**1,414**	666	820
United States Lower 48	2,668	**3,836**	3,122	2,008
International	5,959	**11,206**	6,147	6,685
	9,459	**16,456**	9,935	9,513
Midstream	7	**4**	5	4
R&M				
United States	1,409	**1,643**	1,146	1,597
International	577	**626**	240	1,419
	1,986	**2,269**	1,386	3,016
LUKOIL Investment				2,715
Chemicals				
Emerging Businesses	100	**156**	257	83
Corporate and Other	150	**214**	208	265
	$ 11,702	**19,099**	11,791	15,596

United States	$ 5,076	**7,111**	5,225	4,735
International	6,626	**11,988**	6,566	10,861
	$ 11,702	**19,099**	11,791	15,596

Our capital expenditures and investments for the three-year period ending December 31, 2008, totaled $46.5 billion, with 77 percent going to our E&P segment. Included in these amounts was approximately $4.7 billion related to the October 2008 closing of a transaction with Origin Energy to further enhance our long-term Australasian natural gas business through a 50/50 joint venture named Australia Pacific LNG. The joint venture will focus on coalbed methane production from the Bowen and Surat basins in Queensland, Australia, and LNG processing and export sales. For additional information about the Origin transaction,

Table of Contents

see Note 7 Investments, Loans and Long-Term Receivables, in the Notes to Consolidated Financial Statements.
Our capital expenditures and investments budget for 2009 is $11.7 billion. Included in this amount is approximately $600 million in capitalized interest. The decline from 2008 spending is primarily due to the closing of the transaction with Origin Energy in 2008 and the deferring or slowing of some projects or programs in 2009, as a result of the current business environment. We plan to direct 81 percent of the capital expenditures and investments budget to E&P and 17 percent to R&M. With the addition of loans to certain affiliated companies and principal contributions related to funding our portion of the FCCL business venture, our total capital program for 2009 is approximately $12.5 billion.

E&P

Capital expenditures and investments for E&P during the three-year period ending December 31, 2008, totaled $35.9 billion. The expenditures over this period supported key exploration and development projects including:

Significant U.S. lease acquisitions in the federal waters of the Chukchi Sea offshore Alaska, as well as in the deepwater Gulf of Mexico.

Alaska activities related to development drilling in the Greater Kuparuk Area, including West Sak; the Greater Prudhoe Bay Area; the Alpine field, including satellite field prospects; and the Cook Inlet Area; as well as initiatives to progress the gas pipeline project named Denali The Alaska Gas Pipeline; and exploration activities.

Oil and natural gas developments in the Lower 48, including New Mexico, Texas, Louisiana, Oklahoma, Montana, North Dakota, Colorado, Wyoming, and offshore in the Gulf of Mexico.

Investment in West2East Pipeline LLC, a company holding a 100 percent interest in Rockies Express Pipeline LLC.

Development of the Surmont heavy-oil project, capital expenditures related to the FCCL upstream business venture, and development of conventional oil and gas reserves, all in Canada.

Development drilling and facilities projects in the Greater Ekofisk Area and the Alvheim project, both located in the Norwegian sector of the North Sea.

The Statfjord Late Life project straddling the offshore boundary between Norway and the United Kingdom.

The Britannia satellite developments in the U.K. North Sea.

An integrated project to produce and liquefy natural gas from Qatar s North field.

Expenditures related to the terms under which we returned to our former oil and natural gas production operations in the Waha concessions in Libya and continued development of these concessions.

Ongoing development of onshore oil and natural gas fields in Nigeria and ongoing exploration activities both onshore and within deepwater leases.

The Kashagan field and satellite prospects in the Caspian Sea, offshore Kazakhstan.

Development of the Yuzhno Khylchuyu (YK) field in the northern part of Russia s Timan-Pechora province through the NMNG joint venture with LUKOIL.

The initial investment related to the 50/50 joint venture with Origin Energy.

Projects in offshore Block B and onshore South Sumatra in Indonesia.

The Peng Lai 19-3 development in China s Bohai Bay and additional Bohai Bay appraisal and adjacent field prospects.

The Gumusut-Kakap development offshore Sabah, Malaysia.

2009 CAPITAL EXPENDITURES AND INVESTMENTS BUDGET

E&P s 2009 capital expenditures and investments budget is $9.5 billion, 43 percent lower than actual expenditures in 2008. The decline is primarily due to the 2008 Origin transaction and the deferring or slowing of some projects or programs. Thirty-seven percent of E&P s 2009 capital expenditures and investments budget is planned for the United States.

Table of Contents

Capital spending for our Alaskan operations is expected to fund Prudhoe Bay, Kuparuk and Western North Slope operations, including the Alpine satellite fields, as well as initiatives to progress Denali The Alaska Gas Pipeline, and exploration activities.
In the Lower 48, we expect to make capital expenditures and investments for ongoing development programs in the Permian, San Juan, Williston and Fort Worth basins and the Lobo Trend in South Texas, as well as for development of projects such as the Rockies Express natural gas pipeline.
E&P is directing $6.0 billion of its 2009 capital expenditures and investments budget to international projects. Funds in 2009 will be directed to developing major long-term projects including:

- Oil sands projects, primarily those associated with the FCCL business venture, and ongoing natural gas projects in Canada.
- In the North Sea, the Ekofisk Area, J-Block fields, Greater Britannia fields and various southern North Sea assets.
- The Kashagan field in the Caspian Sea.
- Advancement of coalbed methane projects in Australia associated with the Origin Energy joint venture.
- Continued development of Bohai Bay in China.
- The Gumusut field offshore Malaysia.
- The North Belut field in Block B, as well as other projects offshore Block B and onshore South Sumatra in Indonesia.
- Fields offshore Vietnam.
- Continued development of the Qatargas 3 project in Qatar.
- The Shah gas field in Abu Dhabi.
- Onshore developments in Nigeria, Algeria and Libya.

PROVED UNDEVELOPED RESERVES
The net addition of proved undeveloped reserves accounted for 156 percent, 77 percent and 37 percent of our total net additions in 2008, 2007 and 2006, respectively. During these years, we converted, on average, 15 percent per year of our proved undeveloped reserves to proved developed reserves. Of our 2,823 million total BOE proved undeveloped reserves at December 31, 2008, we estimated that the average annual conversion rate for these reserves for the three-year period ending 2011 will be approximately 15 percent.
Costs incurred for the years ended December 31, 2008, 2007 and 2006, relating to the development of proved undeveloped reserves were $4.8 billion, $4.3 billion, and $3.9 billion, respectively. Estimated future development costs relating to the development of proved undeveloped reserves for the years 2009 through 2011 are projected to be $3.9 billion, $3.1 billion, and $2.0 billion, respectively.
Approximately 80 percent of our proved undeveloped reserves at year-end 2008 were associated with 10 major development areas in our E&P segment, and our investment in LUKOIL. Eight of the major development areas within E&P 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 Ekofisk field in the North Sea.
- The Peng Lai 19-3 field in China.

Fields in the United States.

FCCL heavy-oil projects Christina Lake and Foster Creek in Canada.

The Surmont heavy-oil project in Canada.

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.

Table of Contents

R&M

Capital spending for R&M during the three-year period ending December 31, 2008, 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 $6.7 billion, representing 14 percent of our total capital expenditures and investments.

Key projects during the three-year period included:

- Acquisition of the Wilhelmshaven refinery in Germany.
- Debottlenecking of a crude and fluid catalytic cracking unit, and completion of a new sulfur plant at the Ferndale refinery.
- Installations, revamps and expansions of equipment at all U.S. refineries to enable production of low-sulfur and ultra-low-sulfur fuels.
- Investment to obtain an equity interest in four Keystone pipeline entities (Keystone), a joint venture to construct a crude oil pipeline from Hardisty, Alberta, to delivery points in the United States.
- Installation of a 25,000-barrel-per-day coker and new vacuum unit at the Borger refinery. Commissioning of these units was completed following the formation of the WRB joint venture.
- Upgrading the distillate desulfurization capability at the Humber refinery.

Major construction activities in progress include:

- Expansion of a hydrocracker at the Rodeo facility of our San Francisco refinery.
- Construction of a low-sulfur gasoline project at the Billings refinery.
- Construction of a new sulfur recovery unit at the Sweeny refinery.
- Continued investment in the Keystone Oil Pipeline.
- Construction of a wet gas scrubber at our Alliance refinery.

2009 CAPITAL EXPENDITURES AND INVESTMENTS BUDGET

R&M s 2009 capital budget is $2.0 billion, a 12 percent decrease from actual spending in 2008. Domestic spending in 2009 is expected to comprise 71 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 existing business with a focus on safety, regulatory compliance, reliability and capital maintenance. Work continues on projects to expand conversion capability and increase clean product yield, including funding for the San Francisco hydrocracker project. Our U.S. transportation, marketing and specialty businesses are expected to spend about $300 million, including investments in the Keystone project.

Internationally, we plan to spend about $600 million, with a focus on projects related to reliability, safety and the environment, as well as an upgrade project at the Wilhelmshaven, Germany, refinery. The construction bidding process for the refinery project in Yanbu, Saudi Arabia, is currently scheduled to take place in 2009.

LUKOIL Investment

Capital spending in our LUKOIL Investment segment during the three-year period ending December 31, 2008, was for purchases of ordinary shares of LUKOIL in 2006 to increase our ownership interest. No additional purchases were made in 2007 or 2008, and none are expected in 2009.

Emerging Businesses

Capital spending for Emerging Businesses during the three-year period ending December 31, 2008, was primarily for an expansion of the Immingham combined heat and power cogeneration plant near the company s Humber refinery in the United Kingdom. In addition, in October 2007, we purchased a 50 percent interest in Sweeny Cogeneration LP.

Table of Contents

Contingencies

Legal and Tax Matters

We accrue for non-income-tax-related contingencies when a loss is probable and the amounts can be reasonably estimated. If a range of amounts can be reasonably estimated and no amount within the range is a better estimate than any other amount, then the minimum of the range is accrued. In the case of income-tax-related contingencies, we adopted Financial Accounting Standards Board (FASB) Interpretation No. 48, Accounting for Uncertainty in Income Taxes an interpretation of FASB Statement No. 109 (FIN 48), effective January 1, 2007. FIN 48 requires a cumulative probability-weighted loss accrual in cases where sustaining a tax position is less than certain. Based on currently available information, we believe 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 consolidated financial statements.

Environmental

We are subject to the same numerous international, federal, state and local environmental laws and regulations as 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:

- U.S. Federal Clean Air Act, which governs air emissions.
- U.S. Federal Clean Water Act, which governs discharges to water bodies.
- European Union Regulation for Registration, Evaluation, Authorization and Restriction of Chemicals (REACH).
- U.S. 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 threatening to occur.
- U.S. Federal Resource Conservation and Recovery Act (RCRA), which governs the treatment, storage and disposal of solid waste.
- U.S. 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.
- U.S. Federal Emergency Planning and Community Right-to-Know Act (EPCRA), which requires facilities to report toxic chemical inventories with local emergency planning committees and response departments.
- U.S. 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.
- European Union Trading Directive resulting in European Emissions Trading Scheme.

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 Energy Policy Act of 2005 imposed obligations to provide increasing volumes on a percentage basis of renewable fuels in transportation motor fuels through 2012. These obligations were changed with the enactment of the Energy Independence & Security Act of 2007, which was signed in late December. The new law requires fuel producers and importers to provide approximately 66 percent more renewable fuels in 2008 as compared with amounts set forth in the Energy Policy Act of 2005, with increases in amounts of renewable fuels required through 2022. We are in the process of establishing implementation, operating and capital strategies, along with advanced technology development, to meet these requirements.

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 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.

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 increasing 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, 2007, we reported we had been notified of potential liability under CERCLA and comparable state laws at 68 sites around the United States. At December 31, 2008, we re-opened three sites and closed one of those sites, resolved and closed seven sites, and received two new notices of potential liability, leaving 65 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 $957 million in 2008 and are expected to be about $1.0 billion per year in 2009 and 2010. Capitalized environmental costs were $1,025 million in 2008 and are expected to be about $900 million per year in 2009 and 2010.

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, 2008.

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, 2008, our balance sheet included total accrued environmental costs of $979 million, compared with $1,089 million at December 31, 2007. We expect to incur a substantial amount 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 current environmental laws and regulations.

Climate Change

There has been a broad range of proposed or promulgated state, national and international laws focusing on greenhouse gas (GHG) reduction. These proposed or promulgated laws apply or could apply in countries where we have interests or may have interests in the future. Laws in this field continue to evolve, and while they are 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 relating to implementation. Compliance with changes in laws, regulations and obligations that create a GHG emissions trading scheme or GHG reduction policies generally could significantly increase costs or reduce demand for fossil energy derived products. Examples of legislation or precursors for possible regulation that does or could affect our operations include:

- European Emissions Trading Scheme (ETS), the program through which many of the European Union (EU) member states are implementing the Kyoto Protocol.

- California s Global Warming Solutions Act, 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.

Two regulations issued by the Alberta government in 2007 under the Climate Change and Emissions Act. These regulations require any existing facility with emissions equal to or greater than 100,000 metric tons of carbon dioxide or equivalent per year to reduce the net emissions intensity of that facility by 2 percent per year beginning July 1, 2007, with an ultimate reduction target of 12 percent of baseline emissions.

The U.S. Supreme Court decision in Massachusetts v. EPA, 549 U.S. 497, 127 S.Ct. 1438 (2007) confirming that the U.S. Environmental Protection Agency (EPA) has the authority to regulate carbon dioxide as an air pollutant under the Federal Clean Air Act.

In the EU, we have assets that are subject to the ETS. The first phase of the EU ETS was completed at the end of 2007, with EU ETS phase II running from 2008 through 2012. The European Commission has approved most of the phase II national allocation plans. We are actively engaged to minimize any financial impact from the trading scheme.

In the United States, there is growing consensus that some form of regulation will be forthcoming at the federal level with respect to GHG emissions and such regulation could result in the creation of additional costs in the form of taxes or required acquisition or trading of emission allowances. In light of this consensus, we have taken a position to encourage the adoption of a pragmatic and sustainable regulatory framework addressing GHG. To that end, we joined the U.S. Climate Action Partnership (USCAP) in support of the development of a national regulatory framework to reduce the level of GHG emissions. We support a framework that is economically sustainable, environmentally effective, transparent and fair, and internationally linked. We are working to continuously improve operational and energy efficiency through resource and energy conservation throughout our operations.

Other

We have deferred tax assets related to certain accrued liabilities, loss carryforwards and credit carryforwards. Valuation allowances have been established to reduce these deferred tax assets to an amount that will, more likely than not, be realized. 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 December 2007, the FASB issued Statement of Financial Accounting Standards (SFAS) No. 141 (Revised), Business Combinations (SFAS No. 141(R)). This Statement will apply to all transactions in which an entity obtains control of one or more other businesses. In general, SFAS No. 141(R) requires the acquiring entity in a business combination to recognize the fair value of all the assets acquired and liabilities assumed in the transaction; establishes the acquisition date as the fair value measurement point; and modifies the disclosure requirements. Additionally, it changes the accounting treatment for transaction costs, acquired contingent arrangements, in-process research and development, restructuring costs, changes in deferred tax asset valuation allowances as a result of business combination, and changes in income tax uncertainties after the acquisition date. This Statement applies prospectively to business combinations for which the acquisition date is on or after January 1, 2009. However, starting January 1, 2009, accounting for changes in valuation allowances for acquired deferred tax assets and the resolution of uncertain tax positions for prior business combinations will impact tax expense instead of impacting goodwill.

Also in December 2007, the FASB issued SFAS No. 160, Noncontrolling Interests in Consolidated Financial Statements an amendment of ARB No. 51, which requires noncontrolling interests, also called minority interests, to be presented as a separate item in the equity section of the consolidated balance sheet. It also requires the amount of consolidated net income attributable to the noncontrolling interest to be clearly presented on the face of the consolidated income statement. Additionally, this Statement clarifies that changes in a parent s ownership interest in a subsidiary that do not result in deconsolidation are equity transactions, and when a subsidiary is deconsolidated, it requires gain or loss recognition in net income based on the fair value on the deconsolidation date. This Statement is effective January 1, 2009, and will be applied prospectively

Table of Contents

with the exception of the presentation and disclosure requirements, which must be applied retrospectively for all periods presented.

In March 2008, the FASB issued SFAS No. 161, Disclosures about Derivative Instruments and Hedging Activities an amendment of FASB No. 133. This Statement expands disclosure requirements of SFAS No. 133, Accounting for Derivative Instruments and Hedging Activities, for derivative instruments within the scope of that Statement to provide greater transparency. This includes disclosure of the additional information regarding how and why derivative instruments are used, how derivatives are accounted for, and how they affect an entity s financial performance. This Statement is effective for interim and annual financial statements beginning with the first quarter of 2009, but it will not have any impact on our consolidated financial statements, other than the additional disclosures.

In November 2008, the FASB reached a consensus on Emerging Issues Task Force Issue No. 08-6, Equity Method Investment Accounting Considerations (EITF 08-6), which was issued to clarify how the application of equity method accounting will be affected by SFAS No. 141(R) and SFAS No. 160. EITF 08-6 clarifies that an entity shall continue to use the cost accumulation model for its equity method investments. It also confirms past accounting practices related to the treatment of contingent consideration and the use of the impairment model under Accounting Principles Board (APB) Opinion No. 18, The Equity Method of Accounting for Investments in Common Stock. Additionally, it requires an equity method investor to account for a share issuance by an investee as if the investor had sold a proportionate share of the investment. This issue is effective January 1, 2009, and will be applied prospectively.

In December 2008, the FASB issued FASB Staff Position (FSP) No. 132(R)-1, Employers Disclosures about Postretirement Benefit Plan Assets, to improve the transparency associated with the disclosures about the plan assets of a defined benefit pension or other postretirement plan. This FSP requires the disclosure of each major asset category at fair value using the fair value hierarchy in SFAS No. 157, Fair Value Measurements. Also, this FSP requires entities to disclose the net periodic benefit cost recognized for each annual period for which a statement of income is presented. This FSP is effective for annual statements beginning with 2009.

CRITICAL ACCOUNTING ESTIMATES

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 estimates are discussed with the Audit and Finance Committee of the Board of Directors at least annually. We believe the following discussions of critical accounting estimates, 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 unique to the oil and gas industry. The acquisition of geological and geophysical seismic information, prior to the discovery of proved reserves, is expensed as incurred, similar to accounting for research and development costs. However, leasehold acquisition costs and exploratory well costs are capitalized on the balance sheet pending determination of whether proved oil and gas reserves have been discovered on the prospect.

Property Acquisition Costs

For individually significant leaseholds, management periodically assesses for impairment based on exploration and drilling efforts to date. For leasehold acquisition costs that individually are relatively small, management exercises judgment and determines a percentage probability that the prospect ultimately will fail to find proved oil and gas reserves and pools that leasehold information with others in the geographic area. For prospects in areas that have had limited, or no, previous exploratory drilling, the percentage probability of ultimate failure is normally judged to be quite high. This judgmental percentage is multiplied by the leasehold acquisition cost, and that product is divided by the contractual period of the leasehold to determine a periodic leasehold impairment charge that is reported in exploration expense.

This judgmental probability percentage is reassessed and adjusted throughout the contractual period of the leasehold based on favorable or unfavorable exploratory activity on the leasehold or on adjacent leaseholds, and leasehold impairment amortization expense is adjusted prospectively. At year-end 2008, 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 $1,447 million and the accumulated impairment reserve was $494 million. The weighted-average judgmental percentage probability of ultimate failure was approximately 65 percent, and the weighted-average amortization period was approximately 2.4 years. If that judgmental percentage were to be raised by 5 percent across all calculations, pretax leasehold impairment expense in 2009 would increase by approximately $30 million. The remaining $4,745 million of capitalized unproved property costs at year-end 2008 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 the results of exploration and drilling efforts and the outlook for project commercialization. Of this amount, approximately $2.4 billion is concentrated in 10 major development areas. None of these major assets are expected to move to proved properties in 2009.

Exploratory Costs

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

Once a determination is made the well did not encounter potentially economic oil and gas quantities, the well costs are expensed as a dry hole and reported in exploration expense. If exploratory wells encounter potentially economic quantities of oil and gas, the well costs remain capitalized on the balance sheet as long as sufficient progress assessing the reserves and the economic and operating viability of the project is being made. The accounting notion of sufficient progress is a judgmental area, but the accounting rules do prohibit continued capitalization of suspended well costs on the mere chance that future market conditions will improve or new technologies will be found that would make the project s development economically profitable. Often, the ability to move the project into the development phase and record proved reserves is dependent on obtaining permits and government or co-venturer approvals, the timing of which is ultimately beyond our control. Exploratory well costs remain suspended as long as the company is actively pursuing such approvals and permits, and believes they will be obtained. Once all required approvals and permits have been obtained, the projects are moved into the development phase, and the oil and gas reserves are designated as proved reserves. For complex exploratory discoveries, it is not unusual to have exploratory wells remain suspended on the balance sheet for several years while we perform additional appraisal drilling and seismic work on the potential oil and gas field, or while 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 2008, total suspended well costs were $660 million, compared with $589 million at year-end 2007. For additional information on suspended wells, including an aging analysis, see Note 8 Properties, Plants and Equipment, in the Notes to Consolidated Financial Statements.

Proved Oil and Gas Reserves and Canadian Syncrude Reserves

Engineering estimates of the quantities of recoverable oil and gas reserves in oil and gas fields and in-place crude bitumen volumes in oil sand mining operations are inherently imprecise and represent only approximate amounts because of the subjective judgments involved in developing such information. Reserve estimates are based on subjective judgments involving geological and engineering assessments of in-place hydrocarbon volumes, the production or mining plan, historical extraction recovery and processing yield factors, installed plant operating capacity and operating approval limits. The reliability of these estimates at any point in time depends on both the quality and quantity of the technical and economic data and the efficiency of extracting and processing the hydrocarbons.

Despite the inherent imprecision in these engineering estimates, accounting rules require disclosure of proved reserve estimates due to the importance of these estimates to better understand the perceived value and future cash flows of a company s 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 organization has policies and procedures in place that are consistent with these authoritative guidelines. We have trained and experienced internal engineering personnel who estimate our proved crude oil, natural gas and natural gas liquids reserves held by consolidated companies, as well as our share of equity affiliates, with assistance from third-party petroleum engineering consultants with regard to our equity interests in LUKOIL and Australia Pacific LNG.

Proved reserve estimates are updated annually and take into account recent production and subsurface information about each field or oil sand mining operation. Also, as required by current 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 reserves. Therefore, as prices and cost levels change from year to year, the estimate of proved reserves also changes.

Our proved reserves include estimated quantities related to production sharing contracts, which are reported under the economic interest method and are subject to fluctuations in prices of crude oil, natural gas and natural gas liquids; recoverable operating expenses; and capital costs. If costs remain stable, reserve quantities attributable to recovery of costs will change inversely to changes in commodity prices. For example, if prices increase, then our applicable reserve quantities would decline.

The estimation of proved reserves also is important to the statement of operations 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 2008, 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 $58 billion and the depreciation, depletion and amortization recorded on these assets in 2008 was approximately $7.7 billion. The estimated proved developed oil and gas reserves of these fields were 6.1 billion BOE at the beginning of 2008 and were 5.5 billion BOE at the end of 2008. The estimated proved reserves of Canadian Syncrude assets were 221 million barrels at the beginning of 2008 and were 249 million barrels at the end of 2008. If the 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 2008 would have increased by an estimated $406 million. Impairments of producing oil and gas properties in 2008, 2007 and 2006 totaled $793 million, $471 million and $215 million, respectively. Of these write-downs, $56 million in 2008, $76 million in 2007 and $131 million in 2006 were due to downward revisions of proved reserves due to reservoir performance.

Impairments

Long-lived assets used in operations are assessed for impairment whenever changes in facts and circumstances indicate a possible significant deterioration in the future cash flows expected to be generated by an asset group. If, upon review, the sum of the undiscounted pretax cash flows is less than the carrying value of the asset group, the carrying value is written down to estimated fair value. Individual assets are grouped for impairment purposes based on a judgmental assessment of the lowest level for which there are identifiable cash flows that

are largely independent of the cash flows of other groups of assets generally on a field-by-field basis for exploration and production assets, at an entire complex level for downstream assets, or at a site level for retail stores. Because there usually is a lack of quoted market prices for long-lived assets, the fair value of impaired assets is determined based on the present values of expected future cash flows using discount rates commensurate with the risks involved in the asset group or based on a multiple of operating cash flow validated with historical market transactions of similar assets where possible. The expected future cash flows used for impairment reviews and related fair value calculations are based on judgmental assessments of future production volumes, prices and costs, considering all available information at the date of review. See Note 10 Impairments, in the Notes to Consolidated Financial Statements, for additional information.

Investments in nonconsolidated entities accounted for under the equity method are reviewed for impairment when there is evidence of a loss in value. Such evidence of a loss in value might include our inability to recover the carrying amount, the lack of sustained earnings capacity which would justify the current investment amount, or a current fair value less than the investment s carrying amount. When it is determined such a loss in value is other than temporary, an impairment charge is recognized for the difference between the investment s carrying value and its estimated fair value. When determining whether a decline in value is other than temporary, management considers factors such as the length of time and extent of the decline, the investee s financial condition and near-term prospects, and the company s ability and intention to retain its investment for a period that will be sufficient to allow for any anticipated recovery in the market value of the investment. When quoted market prices are not available, the fair value is usually based on the present value of expected future cash flows using discount rates commensurate with the risks of the investment. Differing assumptions could affect the timing and the amount of an impairment of an investment in any period. For additional information, see the LUKOIL section of Note 7 Investments, Loans and Long-Term Receivables, in the Notes to Consolidated Financial Statements.

Asset Retirement Obligations and Environmental Costs

Under various contracts, permits and regulations, we have material legal obligations to remove tangible equipment and restore the land or seabed at the end of operations at operational sites. Our largest asset removal obligations involve removal and disposal of offshore oil and gas platforms around the world, oil and gas production facilities and pipelines in Alaska, and asbestos abatement at refineries. The fair values of obligations for dismantling and removing these facilities are accrued at the installation of the asset based on estimated discounted costs. 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 Canada and 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.

Table of Contents

Business Acquisitions

Purchase Price Allocation

Accounting for the acquisition of a business requires the allocation of the purchase price to the various assets and liabilities of the acquired business. For most assets and liabilities, purchase price allocation is accomplished by recording the asset or liability at its estimated fair value. The most difficult estimations of individual fair values are those involving properties, plants and equipment and identifiable intangible assets. We use all available information to make these fair value determinations. We have, if necessary, up to one year after the acquisition closing date to finish these fair value determinations and finalize the purchase price allocation.

Intangible Assets and Goodwill

At December 31, 2008, we had $738 million of intangible assets determined to have indefinite useful lives, thus they are not amortized. This judgmental assessment of an indefinite useful life must be continuously evaluated in the future. If, due to changes in facts and circumstances, management determines these intangible assets have definite useful lives, amortization will have to commence at that time on a prospective basis. As long as these intangible assets are judged to have indefinite lives, they will be subject to periodic lower-of-cost-or-market tests that require management s judgment of the estimated fair value of these intangible assets. See Note 9 Goodwill and Intangibles, in the Notes to Consolidated Financial Statements, for additional information.

In the fourth quarter of 2008, we fully impaired the recorded goodwill associated with our Worldwide E&P reporting unit. See the Goodwill Impairment section of Note 9 Goodwill and Intangibles, in the Notes to Consolidated Financial Statements, which is incorporated herein by reference, for a detailed discussion of the facts and circumstances leading to this impairment, as well as the judgments required by management in the analysis leading to the impairment determination. After the goodwill impairment, at December 31, 2008, we had $3,778 million of goodwill remaining on our balance sheet, all of which was attributable to the Worldwide R&M reporting unit.

Projected Benefit Obligations

Determination of the projected benefit obligations for our defined benefit pension and postretirement plans are important to the recorded amounts for such obligations on the balance sheet and to the amount of benefit expense in the statement of operations. 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 and company contribution requirements. For Employee Retirement Income Security Act-qualified pension plans, the actuary exercises fiduciary care on behalf of plan participants in the determination of the judgmental assumptions used in determining required company contributions into plan assets. Due to differing objectives and requirements between financial accounting rules and the pension plan funding regulations promulgated by governmental agencies, the actuarial methods and assumptions for the two purposes differ in certain important respects. Ultimately, we will be required to fund all promised benefits under pension and postretirement benefit plans not funded by plan assets or investment returns, but the judgmental assumptions used in the actuarial calculations significantly affect periodic financial statements and funding patterns over time. Benefit expense is particularly sensitive to the discount rate and return on plan assets assumptions. A 1 percent decrease in the discount rate would increase annual benefit expense by $79 million, while a 1 percent decrease in the return on plan assets assumption would increase annual benefit expense by $43 million. In determining the discount rate, we use yields on high-quality fixed income investments matched to the estimated benefit cash flows of our plans.

Table of Contents

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

This report includes forward-looking statements within the meaning of Section 27A of the Securities Act of 1933 and Section 21E of the Securities Exchange Act of 1934. You can identify our forward-looking statements by the words anticipate, estimate, believe, continue, could, intend, may, plan, potential, predict, should, wi projection, forecast, goal, guidance, outlook, effort, target and similar expressions.

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

Fluctuations in crude oil, natural gas and natural gas liquids prices, refining and marketing margins and margins for our chemicals business.

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

Unsuccessful exploratory drilling activities or the inability to obtain access to exploratory acreage.

Failure of new products and services to achieve market acceptance.

Unexpected changes in costs or technical requirements for constructing, modifying or operating facilities for exploration and production, manufacturing, refining or transportation projects.

Unexpected technological or commercial difficulties in manufacturing, refining, or transporting our products, including synthetic crude oil and chemicals products.

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

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

Failure to complete definitive agreements and feasibility studies for, and to timely complete construction of, announced and future exploration and production, LNG, refinery and transportation projects.

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

International monetary conditions and exchange controls.

Substantial investment or reduced demand for products as a result of existing or future environmental rules and regulations.

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

Liability resulting from litigation.

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

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

Limited access to capital or significantly higher cost of capital related to illiquidity or uncertainty in the domestic or international financial markets.

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

The operation and financing of our midstream and chemicals joint ventures.

The factors generally described in the Risk Factors section included in Item 1A Risk Factors in this report.

Item 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

Financial Instrument Market Risk

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

Our use of derivative instruments is governed by an Authority Limitations document approved by our Board of Directors that prohibits the use of highly leveraged derivatives or derivative instruments without sufficient liquidity for comparable valuations. The Authority Limitations document also authorizes the Chief Operating Officer to establish the maximum Value at Risk (VaR) limits for the company and compliance with these limits is monitored daily. The Chief Financial Officer monitors risks resulting from foreign currency exchange rates and interest rates and reports to the Chief Executive Officer. The Senior Vice President of Commercial monitors commodity price risk and reports to the Chief Operating Officer. The Commercial organization manages our commercial marketing, optimizes our commodity flows and positions, monitors related risks of our upstream and downstream businesses, and selectively takes price risk to add value.

Commodity Price Risk

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

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

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

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

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

Enable us to use the market knowledge gained from these activities to do a limited amount of trading not directly related to our physical business. For the years ended December 31, 2008 and 2007, the gains or losses from this activity were not material to our cash flows or net income.

We use a VaR model to estimate the loss in fair value that could potentially result on a single day from the effect of adverse changes in market conditions on the derivative financial instruments and derivative commodity instruments held or issued, including commodity purchase and sales contracts recorded on the balance sheet at December 31, 2008, as derivative instruments in accordance with SFAS No. 133, Accounting for Derivative Instruments and Hedging Activities, as amended (SFAS No. 133). Using Monte Carlo simulation, a 95 percent confidence level and a one-day holding period, the VaR for those instruments issued or held for trading purposes at December 31, 2008 and 2007, was immaterial to our net income and cash flows.

Table of Contents

The VaR for instruments held for purposes other than trading at December 31, 2008 and 2007, was also immaterial to our net income and cash flows.

Interest Rate Risk

The following tables provide information about our financial instruments that are sensitive to changes in short-term U.S. interest rates. The debt table presents principal cash flows and related weighted-average interest rates by expected maturity dates. Weighted-average variable rates are based on implied forward rates in the yield curve at the reporting date. The carrying amount of our floating-rate debt approximates its fair value. The fair value of the fixed-rate financial instruments is estimated based on quoted market prices.

	Millions of Dollars Except as Indicated			
	Debt			
Expected Maturity Date	Fixed Rate Maturity	Average Interest Rate	Floating Rate Maturity	Average Interest Rate
Year-End 2008				
2009	**$ 303**	**6.43%**	**$ 950**	**4.42%**
2010	**1,441**	**8.83**		
2011	**3,174**	**6.74**	**1,500**	**1.64**
2012	**1,266**	**4.94**	**6,936**	**1.23**
2013	**1,262**	**5.33**	**10**	**2.46**
Remaining years	**9,318**	**6.64**	**628**	**2.58**
Total	**$ 16,764**		**$ 10,024**	
Fair value	**$ 16,882**		**$ 10,024**	
Year-End 2007				
2008	$ 324	7.12%	$ 1,000	5.58%
2009	313	6.44	950	5.47
2010	1,433	8.85		
2011	3,175	6.74	2,000	5.58
2012	1,267	4.94	743	5.43
Remaining years	9,082	6.68	658	4.36
Total	$ 15,594		$ 5,351	
Fair value	$ 17,750		$ 5,351	

Table of Contents

The following tables present principal cash flows of the fixed-rate 5.3 percent joint venture acquisition obligation owed to FCCL Oil Sands Partnership. The fair value of the obligation is estimated based on the net present value of the future cash flows, discounted at a year-end 2008 and 2007 effective yield rate of 5.4 percent and 4.9 percent, respectively, based on yields of U.S. Treasury securities of a similar average duration adjusted for ConocoPhillips average credit risk spread and the amortizing nature of the obligation principal.

	Millions of Dollars Except as Indicated		
	Joint Venture Acquisition Obligation		
Expected Maturity Date	Fixed Rate Maturity		Average Interest Rate
Year-End 2008			
2009	**$**	**625**	**5.30%**
2010		**659**	**5.30**
2011		**695**	**5.30**
2012		**733**	**5.30**
2013		**772**	**5.30**
Remaining years		**2,810**	**5.30**
Total	**$**	**6,294**	
Fair value	**$**	**6,294**	
Year-End 2007			
2008	$	593	5.30%
2009		626	5.30
2010		659	5.30
2011		695	5.30
2012		732	5.30
Remaining years		3,582	5.30
Total	$	6,887	
Fair value	$	7,031	

Table of Contents

Foreign Currency Risk

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

At December 31, 2008 and 2007, we held foreign currency swaps hedging short-term intercompany loans between European subsidiaries and a U.S. subsidiary. Although these swaps hedge exposures to fluctuations in exchange rates, we elected not to utilize hedge accounting as allowed by SFAS No. 133. As a result, the change in the fair value of these foreign currency swaps is recorded directly in earnings. Since the gain or loss on the swaps is offset by the gain or loss from remeasuring the intercompany loans into the functional currency of the lender or borrower, there would be no material impact to income from an adverse hypothetical 10 percent change in the December 31, 2008 or 2007, exchange rates. The notional and fair market values of these positions at December 31, 2008 and 2007, were as follows:

		In Millions			
		Notional*		Fair Market Value**	
Foreign Currency Swaps		**2008**	2007	**2008**	2007
Sell U.S. dollar, buy euro	USD	**526**	744	$ **53**	3
Sell U.S. dollar, buy British pound	USD	**1,657**	1,049	**(46)**	(16)
Sell U.S. dollar, buy Canadian dollar	USD	**1,474**	1,195	**13**	13
Sell U.S. dollar, buy Czech koruna	USD	**40**		**(2)**	
Sell U.S. dollar, buy Danish krone	USD	**5**	20		
Sell U.S. dollar, buy Norwegian kroner	USD	**1,103**	779	**(10)**	15
Sell U.S. dollar, buy Swedish krona	USD	**51**	11	**1**	
Sell U.S. dollar, buy Australian dollar	USD	**246**		**3**	
Sell euro, buy Canadian dollar	EUR	**102**	58		
Buy euro, sell British pound	EUR	**147**	1	**(8)**	3

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

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

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

76

Item 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

CONOCOPHILLIPS

INDEX TO FINANCIAL STATEMENTS

Table of Contents

Report of Management

Management prepared, and is responsible for, the consolidated financial statements and the other information appearing in this annual report. The consolidated financial statements present fairly the company s financial position, results of operations and cash flows in conformity with accounting principles generally accepted in the United States.

In preparing its consolidated financial statements, the company includes amounts that are based on estimates and judgments that management believes are reasonable under the circumstances. The company s financial statements have been audited by Ernst & Young LLP, an independent registered public accounting firm appointed by the Audit and Finance Committee of the Board of Directors and ratified by stockholders. Management has made available to Ernst & Young LLP all of the company s financial records and related data, as well as the minutes of stockholders and directors meetings.

Assessment of Internal Control Over Financial Reporting

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

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

Management assessed the effectiveness of the company s internal control over financial reporting as of December 31, 2008. In making this assessment, it used the criteria set forth by the Committee of Sponsoring Organizations of the Treadway Commission in *Internal Control Integrated Framework*. Based on our assessment, we believe the company s internal control over financial reporting was effective as of December 31, 2008.

Ernst & Young LLP has issued an audit report on the company s internal control over financial reporting as of December 31, 2008.

/s/ James J. Mulva

James J. Mulva
Chairman and
Chief Executive Officer
February 25, 2009

/s/ Sigmund L. Cornelius

Sigmund L. Cornelius
Senior Vice President, Finance,
and Chief Financial Officer

Table of Contents

Report of Independent Registered Public Accounting Firm on Consolidated Financial Statements

The Board of Directors and Stockholders
ConocoPhillips

We have audited the accompanying consolidated balance sheets of ConocoPhillips as of December 31, 2008 and 2007, and the related consolidated statements of operations, changes in common stockholders equity, and cash flows for each of the three years in the period ended December 31, 2008. Our audits also included the related condensed consolidating financial information listed in the Index at Item 8 and financial statement schedule listed in Item 15(a). These financial statements, condensed consolidating financial information, and schedule are the responsibility of the Company s management. Our responsibility is to express an opinion on these financial statements, condensed consolidating financial information, and schedule based on our audits.

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

In our opinion, the financial statements referred to above present fairly, in all material respects, the consolidated financial position of ConocoPhillips at December 31, 2008 and 2007, and the consolidated results of its operations and its cash flows for each of the three years in the period ended December 31, 2008, in conformity with U.S. generally accepted accounting principles. Also, in our opinion, the related condensed consolidating financial information and financial statement schedule, when considered in relation to the basic financial statements taken as a whole, present fairly in all material respects the information set forth therein.

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

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), ConocoPhillips internal control over financial reporting as of December 31, 2008, based on criteria established in *Internal Control Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission and our report dated February 25, 2009 expressed an unqualified opinion thereon.

/s/ Ernst & Young LLP
Houston, Texas
February 25, 2009

Table of Contents

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

The Board of Directors and Stockholders
ConocoPhillips

We have audited ConocoPhillips internal control over financial reporting as of December 31, 2008, based on criteria established in *Internal Control Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission (the COSO criteria). ConocoPhillips management is responsible for maintaining effective internal control over financial reporting, and for its assessment of the effectiveness of internal control over financial reporting included under the heading Assessment of Internal Control Over Financial Reporting in the accompanying Report of Management. Our responsibility is to express an opinion on the Company s internal control over financial reporting based on our audit.

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

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

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

In our opinion, ConocoPhillips maintained, in all material respects, effective internal control over financial reporting as of December 31, 2008, based on the COSO criteria.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the 2008 consolidated financial statements of ConocoPhillips and our report dated February 25, 2009 expressed an unqualified opinion thereon.

/s/ Ernst & Young LLP
Houston, Texas
February 25, 2009

Table of Contents

Consolidated Statement of Operations **ConocoPhillips**

	Millions of Dollars		
Years Ended December 31	**2008**	2007	2006
Revenues and Other Income			
Sales and other operating revenues*	$ **240,842**	187,437	183,650
Equity in earnings of affiliates	**4,250**	5,087	4,188
Other income	**1,090**	1,971	685
Total Revenues and Other Income	**246,182**	194,495	188,523
Costs and Expenses			
Purchased crude oil, natural gas and products	**168,663**	123,429	118,899
Production and operating expenses	**11,818**	10,683	10,413
Selling, general and administrative expenses	**2,229**	2,306	2,476
Exploration expenses	**1,337**	1,007	834
Depreciation, depletion and amortization	**9,012**	8,298	7,284
Impairments			
Goodwill	**25,443**		
LUKOIL investment	**7,410**		
Expropriated assets**		4,588	
Other	**1,686**	442	683
Taxes other than income taxes*	**20,637**	18,990	18,187
Accretion on discounted liabilities	**418**	341	281
Interest and debt expense	**935**	1,253	1,087
Foreign currency transaction losses (gains)	**117**	(201)	(30)
Minority interests	**70**	87	76
Total Costs and Expenses	**249,775**	171,223	160,190
Income (loss) before income taxes	**(3,593)**	23,272	28,333
Provision for income taxes	**13,405**	11,381	12,783
Net Income (Loss)	$ **(16,998)**	11,891	15,550
Net Income (Loss) Per Share of Common Stock *(dollars)*			
Basic	$ **(11.16)**	7.32	9.80
Diluted	**(11.16)**	7.22	9.66
Average Common Shares Outstanding *(in thousands)*			
Basic	**1,523,432**	1,623,994	1,585,982
Diluted	**1,523,432**	1,645,919	1,609,530
* *Includes excise taxes on petroleum products sales:*	*$* ***15,418***	*15,937*	*16,072*

** *Includes allocated*

goodwill.

See Notes to Consolidated Financial Statements.

Table of Contents

Consolidated Balance Sheet **ConocoPhillips**

		Millions of Dollars	
At December 31		**2008**	2007
Assets			
Cash and cash equivalents	$	**755**	1,456
Accounts and notes receivable (net of allowance of $61 million in 2008 and $58 million in 2007)		**10,892**	14,687
Accounts and notes receivable related parties		**1,103**	1,667
Inventories		**5,095**	4,223
Prepaid expenses and other current assets		**2,998**	2,702
Total Current Assets		**20,843**	24,735
Investments and long-term receivables		**30,926**	31,457
Loans and advances related parties		**1,973**	1,871
Net properties, plants and equipment		**83,947**	89,003
Goodwill		**3,778**	29,336
Intangibles		**846**	896
Other assets		**552**	459
Total Assets	$	**142,865**	177,757
Liabilities			
Accounts payable	$	**12,852**	16,591
Accounts payable related parties		**1,138**	1,270
Short-term debt		**370**	1,398
Accrued income and other taxes		**4,273**	4,814
Employee benefit obligations		**939**	920
Other accruals		**2,208**	1,889
Total Current Liabilities		**21,780**	26,882
Long-term debt		**27,085**	20,289
Asset retirement obligations and accrued environmental costs		**7,163**	7,261
Joint venture acquisition obligation related party		**5,669**	6,294
Deferred income taxes		**18,167**	21,018
Employee benefit obligations		**4,127**	3,191
Other liabilities and deferred credits		**2,609**	2,666
Total Liabilities		**86,600**	87,601
Minority Interests		**1,100**	1,173
Common Stockholders Equity			
Common stock (2,500,000,000 shares authorized at $.01 par value)			
Issued (2008 1,729,264,859 shares; 2007 1,718,448,829 shares)			
Par value		**17**	17

Capital in excess of par	**43,396**	42,724
Grantor trusts (at cost: 2008 40,739,129 shares; 2007 42,411,331 shares)	**(702)**	(731)
Treasury stock (at cost: 2008 208,346,815 shares; 2007 104,607,149 shares)	**(16,211)**	(7,969)
Accumulated other comprehensive income (loss)	**(1,875)**	4,560
Unearned employee compensation	**(102)**	(128)
Retained earnings	**30,642**	50,510
Total Common Stockholders Equity	**55,165**	88,983
Total	**$ 142,865**	177,757

See Notes to Consolidated Financial Statements.

Table of Contents

Consolidated Statement of Cash Flows **ConocoPhillips**

	Millions of Dollars		
Years Ended December 31	**2008**	2007*	2006*
Cash Flows From Operating Activities			
Net income (loss)	**$ (16,998)**	11,891	15,550
Adjustments to reconcile net income (loss) to net cash provided by operating activities			
Depreciation, depletion and amortization	**9,012**	8,298	7,284
Impairments	**34,539**	5,030	683
Dry hole costs and leasehold impairments	**698**	463	351
Accretion on discounted liabilities	**418**	341	281
Deferred taxes	**(428)**	(33)	184
Undistributed equity earnings	**(1,609)**	(1,823)	(945)
Gain on asset dispositions	**(891)**	(1,348)	(116)
Other	**(1,064)**	176	(74)
Working capital adjustments**			
Decrease (increase) in accounts and notes receivable	**4,225**	(2,492)	(906)
Decrease (increase) in inventories	**(1,321)**	767	(829)
Decrease (increase) in prepaid expenses and other current assets	**(724)**	487	(372)
Increase (decrease) in accounts payable	**(3,874)**	2,772	657
Increase (decrease) in taxes and other accruals	**675**	21	(232)
Net Cash Provided by Operating Activities	**22,658**	24,550	21,516
Cash Flows From Investing Activities			
Capital expenditures and investments***	**(19,099)**	(11,791)	(15,596)
Acquisition of Burlington Resources Inc.***			(14,285)
Proceeds from asset dispositions	**1,640**	3,572	545
Long-term advances/loans related parties	**(163)**	(682)	(780)
Collection of advances/loans related parties	**34**	89	123
Other	**(28)**	250	
Net Cash Used in Investing Activities	**(17,616)**	(8,562)	(29,993)
Cash Flows From Financing Activities			
Issuance of debt	**7,657**	935	17,314
Repayment of debt	**(1,897)**	(6,454)	(7,082)
Issuance of company common stock	**198**	285	220
Repurchase of company common stock	**(8,249)**	(7,001)	(925)
Dividends paid on company common stock	**(2,854)**	(2,661)	(2,277)
Other	**(619)**	(444)	(185)
Net Cash Provided by (Used in) Financing Activities	**(5,764)**	(15,340)	7,065
	21	(9)	15

Effect of Exchange Rate Changes on Cash and Cash Equivalents				
Net Change in Cash and Cash Equivalents		**(701)**	639	(1,397)
Cash and cash equivalents at beginning of year		**1,456**	817	2,214
Cash and Cash Equivalents at End of Year	**$**	**755**	1,456	817

* *Certain amounts were reclassified to conform to 2008 presentation.*

** *Net of acquisition and disposition of businesses.*

*** *Net of cash acquired.*

See Notes to Consolidated Financial Statements.

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

	Shares of Common Stock			Millions of Dollars							
			Held in	Common Stock				Accumulated Other	Unearned		
	Issued	Held in Treasury	Grantor Trusts	Par Value	Capital in Excess of Par	Treasury Stock	Grantor Trusts	Comprehensive Income (Loss)	Employee Compensation	Retained Earnings	Total
December 31, 2005	1,455,861,340	32,080,000	45,932,093	$ 14	26,754	(1,924)	(778)	814	(167)	28,018	52,731
Net income										15,550	15,550
Other comprehensive income											
Minimum pension liability adjustment								33			33
Foreign currency translation adjustments								1,013			1,013
Hedging activities								4			4
Comprehensive income											16,600
Initial application of SFAS No. 158								(575)			(575)
Cash dividends paid on company common stock										(2,277)	(2,277)
Burlington Resources acquisition	239,733,571	(32,080,000)	890,180	3	14,475	1,924	(53)				16,349
Repurchase of company common stock		15,061,613	(542,000)			(964)	32				(932)
Distributed under incentive compensation and other	9,907,698		(1,921,688)		697		33				730

benefit plans											
Recognition of unearned compensation									19		19
Other										1	1
December 31, 2006	1,705,502,609	15,061,613	44,358,585	17	41,926	(964)	(766)	1,289	(148)	41,292	82,646
Net income										11,891	11,891
Other comprehensive income (loss)											
Defined benefit pension plans:											
Net prior service cost								63			63
Net gain								213			213
Nonsponsored plans								(2)			(2)
Foreign currency translation adjustments								3,075			3,075
Hedging activities								(4)			(4)
Comprehensive income											15,236
Initial application of SFAS No. 158 equity affiliate								(74)			(74)
Cash dividends paid on company common stock										(2,661)	(2,661)
Repurchase of company common stock		89,545,536	(177,110)			(7,005)	11				(6,994)
Distributed under incentive compensation and other benefit plans	12,946,220		(1,856,224)		798		31				829
Recognition of unearned compensation									20		20
Other			86,080				(7)			(12)	(19)

December 31, 2007	1,718,448,829	104,607,149	42,411,331	17	42,724	(7,969)	(731)	4,560	(128)	50,510	88,983
Net loss										**(16,998)**	**(16,998)**
Other comprehensive income (loss)											
Defined benefit pension plans:											
Net prior service cost								**22**			**22**
Net loss								**(950)**			**(950)**
Nonsponsored plans								**(41)**			**(41)**
Foreign currency translation adjustments								**(5,464)**			**(5,464)**
Hedging activities								**(2)**			**(2)**
Comprehensive loss											**(23,433)**
Cash dividends paid on company common stock										**(2,854)**	**(2,854)**
Repurchase of company common stock		**103,739,666**	**(13,600)**			**(8,242)**	**1**				**(8,241)**
Distributed under incentive compensation and other benefit plans	**10,816,030**		**(1,668,456)**		**672**		**28**				**700**
Recognition of unearned compensation									**26**		**26**
Other			**9,854**							**(16)**	**(16)**
December 31, 2008	**1,729,264,859**	**208,346,815**	**40,739,129**	**$ 17**	**43,396**	**(16,211)**	**(702)**	**(1,875)**	**(102)**	**30,642**	**55,165**

See Notes to Consolidated Financial Statements.

Table of Contents

Notes to Consolidated Financial Statements **ConocoPhillips**

Note 1 Accounting Policies

Consolidation Principles and Investments Our consolidated financial statements include the accounts of majority-owned, controlled subsidiaries and variable interest entities where we are the primary beneficiary. The equity method is used to account for investments in affiliates in which we have the ability to exert significant influence over the affiliates operating and financial policies. The cost method is used when we do not have the ability to exert significant influence. Undivided interests in oil and gas joint ventures, pipelines, natural gas plants, terminals and Canadian Syncrude mining operations are consolidated on a proportionate basis. Other securities and investments, excluding marketable securities, are generally carried at cost.

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

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

Revenue Recognition Revenues associated with sales of crude oil, natural gas, natural gas liquids, petroleum and chemical products, and other items are recognized when title passes to the customer, which is when the risk of ownership passes to the purchaser and physical delivery of goods occurs, either immediately or within a fixed delivery schedule that is reasonable and customary in the industry.

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

Revenues from the production of natural gas and crude oil properties, in which we have an interest with other producers, are recognized based on the actual volumes we sold during the period. Any differences between volumes sold and entitlement volumes, based on our net working interest, which are deemed to be nonrecoverable through remaining production, are recognized as accounts receivable or accounts payable, as appropriate. Cumulative differences between volumes sold and entitlement volumes are generally not significant.

Revenues associated with royalty fees from licensed technology are recorded based either upon volumes produced by the licensee or upon the successful completion of all substantive performance requirements related to the installation of licensed technology.

Shipping and Handling Costs Our Exploration and Production (E&P) segment includes shipping and handling costs in production and operating expenses for production activities. Transportation costs related to E&P marketing activities are recorded in purchased crude oil, natural gas and products. The

Refining and Marketing (R&M) segment records shipping and handling costs in purchased crude oil, natural gas and products. Freight costs billed to customers are recorded as a component of revenue.

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

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

Derivative Instruments All derivative instruments are recorded on the balance sheet at fair value in either prepaid expenses and other current assets, other assets, other accruals, or other liabilities and deferred credits. If the right of offset exists and the other criteria of Financial Accounting Standards Board (FASB) Interpretation No. 39, Offsetting of Amounts Related to Certain Contracts an interpretation of APB Opinion No. 10 and FASB Statement No. 105 (FIN 39), are met, derivative assets and liabilities with the same counterparty are netted on the balance sheet and collateral payable or receivable is netted against derivative assets and derivative liabilities, respectively.

Recognition and classification of the gain or loss that results from recording and adjusting a derivative to fair value depends on the purpose for issuing or holding the derivative. Gains and losses from derivatives that are not accounted for as hedges under Statement of Financial Accounting Standards (SFAS) No. 133, Accounting for Derivative Instruments and Hedging Activities, are recognized immediately in earnings. For derivative instruments that are designated and qualify as a fair value hedge, the gains or losses from adjusting the derivative to its fair value will be immediately recognized in earnings and, to the extent the hedge is effective, offset the concurrent recognition of changes in the fair value of the hedged item. Gains or losses from derivative instruments that are designated and qualify as a cash flow hedge or hedge of a net investment in a foreign entity will be recorded on the balance sheet in accumulated other comprehensive income (loss) until the hedged transaction is recognized in earnings; however, to the extent the change in the value of the derivative exceeds the change in the anticipated cash flows of the hedged transaction, the excess gains or losses will be recognized immediately in earnings.

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

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

Property Acquisition Costs Oil and gas leasehold acquisition costs are capitalized and included in the balance sheet caption properties, plants and equipment. Leasehold impairment is recognized based on exploratory experience and management s judgment. Upon achievement of all conditions necessary for the classification of reserves as proved, the associated leasehold costs are reclassified to proved properties.

Exploratory Costs Geological and geophysical costs and the costs of carrying and retaining undeveloped properties are expensed as incurred. Exploratory well costs are capitalized, or suspended, on the balance sheet pending further evaluation of whether economically recoverable reserves have been found. If economically recoverable reserves are not found, exploratory well costs are expensed as dry holes. If exploratory wells encounter potentially economic quantities of oil and gas, the well costs remain capitalized on the balance sheet as long as sufficient progress assessing the reserves and the economic and operating viability of the project is being made. For complex exploratory discoveries, it is not unusual to have exploratory wells remain suspended on the balance sheet for several years while we perform additional appraisal drilling and seismic work on the potential oil and gas field, or while we seek government or co-venturer approval of development plans or seek environmental permitting. Once all required approvals and permits have been obtained, the projects are moved into the development phase, and the oil and gas reserves are designated as proved reserves.

Management reviews suspended well balances quarterly, continuously monitors the results of the additional appraisal drilling and seismic work, and expenses the suspended well costs as a dry hole when it judges that the potential field does not warrant further investment in the near term.

See Note 8 Properties, Plants and Equipment, for additional information on suspended wells.

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

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

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

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

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

Table of Contents

Goodwill Goodwill is not amortized but is tested at least annually for impairment. If the fair value of a reporting unit is less than the recorded book value of the reporting unit s assets (including goodwill), less liabilities, then a hypothetical purchase price allocation is performed on the reporting unit s assets and liabilities using the fair value of the reporting unit as the purchase price in the calculation. If the amount of goodwill resulting from this hypothetical purchase price allocation is less than the recorded amount of goodwill, the recorded goodwill is written down to the new amount. For purposes of goodwill impairment calculations, two reporting units have been determined: Worldwide Exploration and Production and Worldwide Refining and Marketing.

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

Impairment of Properties, Plants and Equipment Properties, plants and equipment used in operations are assessed for impairment whenever changes in facts and circumstances indicate a possible significant deterioration in the future cash flows expected to be generated by an asset group. If, upon review, the sum of the undiscounted pretax cash flows is less than the carrying value of the asset group, the carrying value is written down to estimated fair value through additional amortization or depreciation provisions and reported as impairments in the periods in which the determination of the impairment is made. Individual assets are grouped for impairment purposes at the lowest level for which there are identifiable cash flows that are largely independent of the cash flows of other groups of assets generally on a field-by-field basis for exploration and production assets, at an entire complex level for refining assets or at a site level for retail stores. Because there usually is a lack of quoted market prices for long-lived assets, the fair value of impaired assets is determined based on the present values of expected future cash flows using discount rates commensurate with the risks involved in the asset group or based on a multiple of operating cash flow validated with historical market transactions of similar assets where possible. Long-lived assets committed by management for disposal within one year are accounted for at the lower of amortized cost or fair value, less cost to sell.

The expected future cash flows used for impairment reviews and related fair value calculations are based on estimated future production volumes, prices and costs, considering all available evidence at the date of review. If the future production price risk has been hedged, the hedged price is used in the calculations for the period and quantities hedged. The impairment review includes cash flows from proved developed and undeveloped reserves, including any development expenditures necessary to achieve that production. Additionally, when probable reserves exist, an appropriate risk-adjusted amount of these reserves may be included in the impairment calculation. The price and cost outlook assumptions used in impairment reviews differ from the assumptions used in the Standardized Measure of Discounted Future Net Cash Flows Relating to Proved Oil and Gas Reserve Quantities. In that disclosure, SFAS No. 69, Disclosures about Oil and Gas Producing Activities, requires inclusion of only proved reserves and the use of prices and costs at the balance sheet date, with no projection for future changes in assumptions.

Impairment of Investments in Nonconsolidated Entities Investments in nonconsolidated entities are assessed for impairment whenever changes in the facts and circumstances indicate a loss in value has occurred, which is other than a temporary decline in value. The fair value of the impaired investment is based on quoted market prices, if available, or upon the present value of expected future cash flows using discount rates commensurate with the risks of the investment.

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

Table of Contents

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

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

Asset Retirement Obligations and Environmental Costs We record the fair value of legal obligations to retire and remove long-lived assets in the period in which the obligation is incurred (typically when the asset is installed at the production location). When the liability is initially recorded, we capitalize this cost by increasing the carrying amount of the related properties, plants and equipment. Over time the liability is increased for the change in its present value, and the capitalized cost in properties, plants and equipment is depreciated over the useful life of the related asset. See Note 11 Asset Retirement Obligations and Accrued Environmental Costs, for additional information.

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

Guarantees The fair value of a guarantee is determined and recorded as a liability at the time the guarantee is given. The initial liability is subsequently reduced as we are released from exposure under the guarantee. We amortize the guarantee liability over the relevant time period, if one exists, based on the facts and circumstances surrounding each type of guarantee. In cases where the guarantee term is indefinite, we reverse the liability when we have information that the liability is essentially relieved or amortize it over an appropriate time period as the fair value of our guarantee exposure declines over time. We amortize the guarantee liability to the related statement of operations line item based on the nature of the guarantee. When it becomes probable that we will have to perform on a guarantee, we accrue a separate liability if it is reasonably estimable, based on the facts and circumstances at that time. We reverse the fair value liability only when there is no further exposure under the guarantee.

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

Employee stock options granted prior to 2003 were accounted for under Accounting Principles Board (APB) Opinion No. 25, Accounting for Stock Issued to Employees, and related Interpretations; however, by the end of 2005, all of these awards had vested.

Generally, our stock-based compensation programs provided accelerated vesting (i.e., a waiver of the remaining period of service required to earn an award) for awards held by employees at the time of their retirement. We recognized expense for these awards over the period of time during which the employee earned the award, accelerating the recognition of expense only when an employee actually retired.

Effective January 1, 2006, we adopted SFAS No. 123 (revised 2004), Share-Based Payment (SFAS No. 123(R)), which requires us to recognize stock-based compensation expense for new awards over the shorter of: 1) the service period (i.e., the stated period of time required to earn the award); or 2) the period beginning at the start of the service period and ending when an employee first becomes eligible for retirement. This shortens the period over which we recognize expense for most of our stock-based awards granted to our employees who are already age 55 or older, but it has not had a material effect on our consolidated financial statements. For share-based awards granted after our adoption of SFAS No. 123(R), we have elected to recognize expense on a straight-line basis over the service period for the entire award, whether the award was granted with ratable or cliff vesting.

Income Taxes Deferred income taxes are computed using the liability method and are provided on all temporary differences between the financial reporting basis and the tax basis of our assets and liabilities, except for deferred taxes on income considered to be permanently reinvested in certain foreign subsidiaries and foreign corporate joint ventures. Allowable tax credits are applied currently as reductions of the provision for income taxes. Interest related to unrecognized tax benefits is reflected in interest expense, and penalties in production and operating expenses.

Taxes Collected from Customers and Remitted to Governmental Authorities Excise taxes are reported gross within sales and other operating revenues and taxes other than income taxes, while other sales and value-added taxes are recorded net in taxes other than income taxes.

Net Income (Loss) Per Share of Common Stock Basic net income (loss) per share of common stock is calculated based upon the daily weighted-average number of common shares outstanding during the year, including unallocated shares held by the stock savings feature of the ConocoPhillips Savings Plan. Also, this calculation includes fully vested stock and unit awards that have not been issued. Diluted net income per share of common stock includes the above, plus unvested stock, unit or option awards granted under our compensation plans and vested but unexercised stock options, but only to the extent these instruments dilute net income per share. Diluted net loss per share is calculated the same as basic net loss per share that is, it does not assume conversion or exercise of securities, totaling 17,354,959 in 2008, that would have an antidilutive effect. Treasury stock and shares held by the grantor trusts are excluded from the daily weighted-average number of common shares outstanding in both calculations.

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

Note 2 Changes in Accounting Principles

SFAS No. 157

Effective January 1, 2008, we implemented FASB SFAS No. 157, Fair Value Measurements, which defines fair value, establishes a framework for its measurement and expands disclosures about fair value measurements. We elected to implement this Statement with the one-year deferral permitted by FASB Staff Position (FSP) 157-2 for nonfinancial assets and nonfinancial liabilities measured at fair value, except those that are recognized or disclosed on a recurring basis (at least annually). The deferral applies to nonfinancial assets and liabilities measured at fair value in a business combination; impaired properties, plants and equipment; intangible assets and goodwill; and initial recognition of asset retirement obligations and restructuring costs for which we use fair value. We do not expect any significant impact to our consolidated financial statements when we implement SFAS No. 157 for these assets and liabilities.

Due to our election under FSP 157-2, for 2008, SFAS No. 157 applies to commodity and foreign currency derivative contracts and certain nonqualified deferred compensation and retirement plan assets that are

Table of Contents

measured at fair value on a recurring basis in periods subsequent to initial recognition. The implementation of SFAS No. 157 did not cause a change in the method of calculating fair value of assets or liabilities, with the exception of incorporating the impact of our nonperformance risk on derivative liabilities which was not material. The primary impact from adoption was additional disclosures.

SFAS No. 157 requires disclosures that categorize assets and liabilities measured at fair value into one of three different levels depending on the observability of the inputs employed in the measurement. Level 1 inputs are quoted prices in active markets for identical assets or liabilities. Level 2 inputs are observable inputs other than quoted prices included within Level 1 for the asset or liability, either directly or indirectly through market-corroborated inputs. Level 3 inputs are unobservable inputs for the asset or liability reflecting significant modifications to observable related market data or our assumptions about pricing by market participants.

We value our exchange-cleared derivatives using closing prices provided by the exchange as of the balance sheet date, and these are classified as Level 1 in the fair value hierarchy. Over the counter (OTC) financial swaps and physical commodity purchase and sale contracts are generally valued using quotations provided by brokers and price index developers such as Platts and Oil Price Information Service. These quotes are corroborated with market data and are classified as Level 2. In certain less liquid markets or for longer-term contracts, forward prices are not as readily available. In these circumstances, OTC swaps and physical commodity purchase and sale contracts are valued using internally developed methodologies that consider historical relationships among various commodities that result in management s best estimate of fair value. These contracts are classified as Level 3.

Exchange-cleared financial options are valued using exchange closing prices and are classified as Level 1. Financial OTC and physical commodity options are valued using industry-standard models that consider various assumptions, including quoted forward prices for commodities, time value, volatility factors, and contractual prices for the underlying instruments, as well as other relevant economic measures. The degree to which these inputs are observable in the forward markets determines whether the option is classified as Level 2 or 3.

As permitted under SFAS No. 157, we use a mid-market pricing convention (the mid-point between bid and ask prices). When appropriate, valuations are adjusted to reflect credit considerations, generally based on available market evidence.

The fair value hierarchy for our financial assets and liabilities accounted for at fair value on a recurring basis at December 31, 2008, was:

	Millions of Dollars			
	Level 1	Level 2	Level 3	Total
Assets				
Commodity derivatives	$ 4,994	2,874	112	7,980
Foreign exchange derivatives		97		97
Nonqualified benefit plans	315	1		316
Total assets	5,309	2,972	112	8,393
Liabilities				
Commodity derivatives	(5,221)	(2,497)	(72)	(7,790)
Foreign exchange derivatives		(93)		(93)
Total liabilities	(5,221)	(2,590)	(72)	(7,883)
Net assets	$ 88	382	40	510

The derivative values above are based on an analysis of each contract as the fundamental unit of account as required by SFAS No. 157; therefore, derivative assets and liabilities with the same counterparty are not netted

Table of Contents

where the legal right of offset exists, which is different than the net presentation basis in Note 16 Financial Instruments and Derivative Contracts. Gains or losses from contracts in one level may be offset by gains or losses on contracts in another level or by changes in values of physical contracts or positions that are not reflected in the table above.
During 2008, the fair value of net commodity derivatives classified as Level 3 in the fair value hierarchy changed as follows:

	Millions of Dollars
Fair Value Measurements Using Significant Unobservable Inputs (Level 3)	
Balance at January 1	$ (34)
Total gains (losses), realized and unrealized	
Included in earnings	**6**
Included in other comprehensive income	
Purchases, issuances and settlements	**37**
Transfers in and/or out of Level 3	**31**
Balance at December 31, 2008	**$ 40**

The amount of Level 3 total gains (losses) included in earnings for 2008 attributable to the change in unrealized gains (losses) relating to assets and liabilities held at December 31, 2008, were:

	Millions of Dollars
Related to assets	$ 83
Related to liabilities	(72)

Level 3 gains and losses, realized and unrealized, included in earnings for 2008 were:

	Millions of Dollars		
	Other Operating Revenues	Purchased Crude Oil, Natural Gas and Products	Total
Total gains (losses) included in earnings	$ 11	(5)	6
Change in unrealized gains (losses) relating to assets held at December 31, 2008	$ 20	63	83
Change in unrealized gains (losses) relating to liabilities held at December 31, 2008	$ (8)	(64)	(72)

SFAS No. 159

In February 2007, the FASB issued SFAS No. 159, The Fair Value Option for Financial Assets and Financial Liabilities Including an amendment of FASB Statement No. 115. This Statement permits the election to carry financial instruments and certain other items similar to financial instruments at fair value on the balance sheet, with all changes in fair value reported in earnings. By electing the fair value option in conjunction with a derivative, an entity can achieve an accounting result similar to a fair value hedge without having to comply with complex hedge accounting rules. We adopted this Statement effective January 1, 2008, but did not make a fair value election at that time or during the remainder of 2008 for any financial instruments not already carried at fair value in accordance with other accounting standards. Accordingly, the adoption of SFAS No. 159 did not impact our consolidated financial statements.

Other

In December 2008, the FASB issued FSP FAS 140-4 and FIN 46(R)-8, Disclosures about Transfers of Financial Assets and Interest in Variable Interest Entities. This FSP requires additional disclosures about an entity s involvement with a variable interest entity (VIE) and certain transfers of financial assets to special-purpose entities and VIEs. This FSP was effective December 31, 2008, and the additional disclosures related to VIEs have been incorporated into Note 4 Variable Interest Entities (VIEs), including the methodology for determining whether we are the primary beneficiary of a VIE, whether we have provided financial or other support we were not contractually required to provide, and other qualitative and quantitative information. We did not have any transfers of financial assets within the scope of this FSP.

During 2008, we implemented FSP FIN 39-1, Amendment of FASB Interpretation No. 39, which requires a reporting entity to offset rights to reclaim cash collateral or obligations to return cash collateral against derivative assets and liabilities executed with the same counterparty, if the entity elects to use netting in accordance with the criteria of FIN 39. The adoption did not have a material effect on our financial statements. For more information on FSP FIN 39-1, see the Derivative Instruments section of Note 1 Accounting Policies.

In June 2006, the FASB issued 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 requires recognition of a tax benefit if it is more likely than not it will be sustained upon examination. We adopted FIN 48 effective January 1, 2007. The adoption did not have a material impact on our consolidated financial statements. See Note 21 Income Taxes, for additional information about income taxes.

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

The table below shows the actual 2008 and 2007, sales and other operating revenues, and purchased crude oil, natural gas and products under Issue No. 04-13, and the respective pro forma amounts had this new guidance been effective for periods prior to April 1, 2006.

	Millions of Dollars		
	Actual		Pro Forma
	2008	2007	2006
Sales and other operating revenues	$ **240,842**	187,437	176,993
Purchased crude oil, natural gas and products	**168,663**	123,429	112,242

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

- Recognize the funded status of the benefit in its statement of financial position.
- Recognize as a component of other comprehensive income, net of tax, the gains or losses and prior service costs or credits that arise during the period, but are not recognized as components of net periodic benefit cost.
- Measure defined benefit plan assets and obligations as of the date of the employer s fiscal year-end statement of financial position.
- Disclose in the notes to financial statements additional information about certain effects on net periodic benefit cost for the next fiscal year that arise from delayed recognition of the gains or losses, prior service costs or credits, and the transition asset or obligation.

We adopted the provisions of this Statement effective December 31, 2006, except for the requirement to measure plan assets and benefit obligations as of the date of the employer s fiscal year end, which we adopted effective December 31, 2008. For information on the impact of the adoption of this new Statement, see Note 20 Employee Benefit Plans.

Note 3 Acquisition of Burlington Resources Inc.

On March 31, 2006, we completed the $33.9 billion acquisition of Burlington Resources Inc., an independent exploration and production company that held a substantial position in North American natural gas proved reserves, production and exploratory acreage. We issued approximately 270.4 million shares of our common stock and paid approximately $17.5 billion in cash.

The final allocation of the purchase price to specific assets and liabilities was completed in the first quarter of 2007. It was based on the fair value of Burlington Resources long-lived assets and the conclusion of the fair value determination of all other Burlington Resources assets and liabilities.

The following table presents pro forma information for 2006 as if the acquisition had occurred at the beginning of 2006.

	Millions of Dollars
Pro Forma	
Sales and other operating revenues	$ 185,555
Income from continuing operations	15,945
Net income	15,945
Income from continuing operations per share of common stock	
Basic	9.65
Diluted	9.51
Net income per share of common stock	
Basic	9.65
Diluted	9.51

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

Note 4 Variable Interest Entities (VIEs)

We hold significant variable interests in VIEs that have not been consolidated because we are not considered the primary beneficiary. Information on these VIEs follows:

We own a 24 percent interest in West2East Pipeline LLC, a company holding a 100 percent interest in Rockies Express Pipeline LLC. Rockies Express is constructing a natural gas pipeline from Colorado to Ohio. West2East is a VIE because a third party has a 49 percent voting interest through the end of the construction of the pipeline, but has no ownership interest. This third party was originally involved in the project, but exited and retained their voting interest to ensure project completion. We have no voting interest during the construction phase, but once the pipeline has been completed, our ownership will increase to 25 percent with a voting interest of 25 percent. Additionally, we have contracted for approximately 22 percent of the pipeline capacity for a 10-year period once the pipeline becomes operational. Construction commenced on the pipeline in 2006 and is expected to be completed in late 2009. Total construction costs are projected to be approximately $6.3 billion and our portion is expected to be funded by a combination of equity contributions and a guarantee of debt incurred by Rockies Express. Given our 24 percent ownership and the fact the expected returns are shared among the equity holders in proportion to ownership, we are not the primary beneficiary. We use the equity method of accounting for our investment. In 2006, we issued a guarantee for 24 percent of the $2 billion in credit facilities of Rockies Express. In addition, we have a guarantee for 24 percent of $600 million of Floating Rate Notes due 2009 issued by Rockies Express. At December 31, 2008, the book value of our investment in West2East was $242 million.

We have a 30 percent ownership interest with a 50 percent governance interest in the OOO Naryanmarneftegaz (NMNG) joint venture to develop resources in the Timan-Pechora province of Russia. The NMNG joint venture is a VIE because we and our related party, OAO LUKOIL, have disproportionate interests. When related parties are involved in a VIE, FIN 46(R) indicates that reasonable judgment should take into account the relevant facts and circumstances for the determination of the primary beneficiary. The activities of NMNG are more closely aligned with LUKOIL since they share Russia as a home country and LUKOIL conducts extensive exploration activities in the same province. Additionally, there are no financial guarantees given by LUKOIL or us, and LUKOIL owns 70 percent, versus our 30 percent direct interest. As a result, we have determined we are not the primary beneficiary of NMNG, and we use the equity method of accounting for this investment. The funding of NMNG has been provided with equity contributions for the development of the Yuzhno Khylchuyu (YK) field. Initial production from YK was achieved in June 2008. At December 31, 2008, the book value of our investment in the venture was $1,751 million.

Production from the NMNG joint venture fields is transported via pipeline to LUKOIL s terminal at Varandey Bay on the Barents Sea and then shipped via tanker to international markets. LUKOIL completed an expansion of the terminal s gross oil-throughput capacity from 30,000 barrels per day to 240,000 barrels per day, with us participating in the design and financing of the expansion. The terminal entity, Varandey Terminal Company, is a VIE because we and our related party, LUKOIL, have disproportionate interests. We had an obligation to fund, through loans, 30 percent of the terminal s costs, but have no governance or direct ownership interest in the terminal. Similar to NMNG, we determined we are not the primary beneficiary for Varandey because of LUKOIL s ownership, the activities are in LUKOIL s home country, and LUKOIL is the operator of Varandey. We account for our loan to Varandey as a financial asset. Terminal construction was completed in June 2008, and the final loan amount was $275 million at December 2008 exchange rates, excluding accrued interest. Although repayments are not required to start until May 2010, Varandey did repay $12 million of interest in the second half of 2008 with available cash. The outstanding accrued interest at December 31, 2008, was $38 million at December exchange rates.

We have an agreement with Freeport LNG Development, L.P. (Freeport LNG) to participate in a liquefied natural gas (LNG) receiving terminal in Quintana, Texas. We have no ownership in Freeport LNG; however, we obtained a 50 percent interest in Freeport LNG GP, Inc (Freeport GP), which serves as the general partner

Table of Contents

managing the venture. We entered into a credit agreement with Freeport LNG, whereby we agreed to provide loan financing for the construction of the terminal. We also entered into a long-term agreement with Freeport LNG to use 0.9 billion cubic feet per day of regasification capacity. The terminal became operational in June 2008, and we began making payments under the terminal use agreement. In August 2008, the loan was converted from a construction loan to a term loan and consisted of $650 million in loan financing and $124 million of accrued interest. Freeport LNG began making loan repayments in September 2008 and the loan balance outstanding as of December 31, 2008, was $757 million. Freeport LNG is a VIE because Freeport GP holds no equity in Freeport LNG and the limited partners of Freeport LNG do not have any substantive decision making ability. We performed an analysis of the expected losses and determined we are not the primary beneficiary. This expected loss analysis took into account that the credit support arrangement requires Freeport LNG to maintain sufficient commercial insurance to mitigate any loan losses. The loan to Freeport LNG is accounted for as a financial asset, and our investment in Freeport GP is accounted for as an equity investment.

In the case of Ashford Energy Capital S.A., we consolidate this entity in our financial statements because we are the primary beneficiary of this VIE based on an analysis of the variability of the expected losses and expected residual returns. In December 2001, in order to raise funds for general corporate purposes, ConocoPhillips and Cold Spring Finance S.a.r.l. formed Ashford 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 consisting of 1.32 percent plus a three-month LIBOR rate set at the beginning of each quarter. The preferred return at December 31, 2008, was 5.37 percent. In 2008, Cold Spring declined its option to remarket its investment in Ashford. This option remains available in 2018 and at each 10-year anniversary thereafter. If remarketing is unsuccessful, we could be required to provide a letter of credit in support of Cold Spring s investment, or in the event such a letter of credit is not provided, cause the redemption of Cold Spring s investment in Ashford. Should our credit rating fall below investment grade, Ashford would require a letter of credit to support $475 million of the term loans, as of December 31, 2008, 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, 2008, Ashford held $2.0 billion of ConocoPhillips subsidiary notes and $28 million in investments unrelated to ConocoPhillips. We report Cold Spring s investment as a minority interest because it is not mandatorily redeemable, and the entity does not have a specified liquidation date. Other than the obligation to make payment on the subsidiary notes described above, Cold Spring does not have recourse to our general credit.

Note 5 Inventories

Inventories at December 31 were:

		Millions of Dollars	
		2008	2007
Crude oil and petroleum products	$	**4,232**	3,373
Materials, supplies and other		**863**	850
	$	**5,095**	4,223

Inventories valued on a LIFO basis totaled $3,939 million and $2,974 million at December 31, 2008 and 2007, respectively. The remaining inventories were valued under various methods, including FIFO and weighted average. The excess of current replacement cost over LIFO cost of inventories amounted to $1,959 million and $6,668 million at December 31, 2008 and 2007, respectively.

Table of Contents

During 2008, certain international inventory quantity reductions caused a liquidation of LIFO inventory values resulting in a $39 million benefit to our R&M segment net income. In 2007, a liquidation of LIFO inventory values increased net income $280 million, of which $260 million was attributable to our R&M segment. Comparable amounts in 2006 increased net income $39 million, of which $32 million was attributable to our R&M segment.

Note 6 Assets Held for Sale

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

During 2007 and 2008, a significant portion of these held-for-sale assets were sold, additional assets met the held-for-sale criteria, and other assets no longer met the held-for-sale criteria. As a result, at December 31, 2008 and 2007, we classified $594 million and $1,092 million, respectively, of noncurrent assets as Prepaid expenses and other current assets on our consolidated balance sheet. In addition, we classified $92 million at year-end 2008 and $159 million at year-end 2007 of noncurrent liabilities as current liabilities, consisting of $78 million for 2008 and $133 million for 2007 in Accrued income and other taxes and $14 million and $26 million, respectively, in Other accruals.

The major classes of noncurrent assets and noncurrent liabilities held for sale and classified to current at December 31 were:

		Millions of Dollars	
		2008	2007
Assets			
Investments and long-term receivables	**$**	**2**	48
Net properties, plants and equipment		**590**	946
Goodwill			89
Intangibles		**2**	2
Other assets			7
Total assets reclassified	**$**	**594**	1,092
Exploration and Production	**$**	**40**	189
Refining and Marketing		**554**	903
	$	**594**	1,092
Liabilities			
Asset retirement obligations and accrued environmental costs	**$**	**14**	23
Deferred income taxes		**78**	133
Other liabilities and deferred credits			3
Total liabilities reclassified	**$**	**92**	159
Exploration and Production	**$**		35
Refining and Marketing		**92**	124

	$	**92**	159

Table of Contents

In January 2009, we closed on the sale of a large part of our U.S. retail marketing assets, which included seller financing in the form of a $370 million five-year note and letters of credit totaling $54 million. Accordingly, this reduced the R&M noncurrent assets held for sale and reclassified as current from $554 million to $152 million, and reduced the noncurrent liabilities reclassified as current from $92 million to $24 million, which includes $19 million of deferred taxes. We expect the disposal of the remaining held-for-sale assets to be completed in 2009.

Note 7 Investments, Loans and Long-Term Receivables

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

	Millions of Dollars	
	2008	2007
Equity investments	**$ 29,914**	30,408
Loans and advances related parties	**1,973**	1,871
Long-term receivables	**597**	495
Other investments	**415**	554
	$ 32,899	33,328

Equity Investments

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

Australia Pacific LNG 50 percent owned joint venture with Origin Energy to develop coalbed methane production from the Bowen and Surat basins in Queensland, Australia, as well as process and export LNG.

FCCL Oil Sands Partnership 50 percent owned business venture with EnCana Corporation produces heavy oil in the Athabasca oil sands in northeastern Alberta, as well as transports and sells the bitumen blend.

WRB Refining LLC 50 percent owned business venture with EnCana Corporation processes crude oil at the Wood River and Borger refineries, as well as purchases and transports all feedstocks for the refineries and sells the refined products.

OAO LUKOIL 20 percent ownership interest. LUKOIL explores for and produces crude oil, natural gas and natural gas liquids; refines, markets and transports crude oil and petroleum products; and is headquartered in Russia.

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

DCP Midstream, LLC 50 percent owned joint venture with Spectra Energy owns and operates gas plants, gathering systems, storage facilities and fractionation plants.

Chevron Phillips Chemical Company LLC (CPChem) 50 percent owned joint venture with Chevron Corporation manufactures and markets petrochemicals and plastics.

Table of Contents

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

	Millions of Dollars		
	2008	2007	2006
Revenues	$ **180,070**	143,686	113,607
Income before income taxes	**22,356**	19,807	16,257
Net income	**17,976**	15,229	12,447
Current assets	**34,838**	29,451	24,820
Noncurrent assets	**114,294**	90,939	59,803
Current liabilities	**21,150**	16,882	15,884
Noncurrent liabilities	**29,845**	26,656	20,603

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

At December 31, 2008, retained earnings included $1,178 million related to the undistributed earnings of affiliated companies. Distributions received from affiliates were $3,259 million, $3,326 million and $3,294 million in 2008, 2007 and 2006, respectively.

Australia Pacific LNG

In October 2008, we closed on a transaction with Origin Energy, an integrated Australian energy company, to further enhance our long-term Australasian natural gas business. The 50/50 joint venture will focus on coalbed methane production from the Bowen and Surat basins in Queensland, Australia, and LNG processing and export sales.

This transaction gives us access to coalbed methane resources in Australia and enhances our LNG position with the expected creation of an additional LNG hub targeting the Asia Pacific markets.

Under the terms of the transaction, we paid $5 billion at closing, which after the effect of hedging gains, resulted in an initial cash acquisition cost of $4.7 billion. In addition, we will be responsible for AU$1.15 billion related to Origin s initial share of joint venture funding requirements, when incurred. We have committed to make up to four additional payments of $500 million each, expected within the next decade, conditional on each of four expected LNG trains being approved by the joint venture for development, for a total possible cash acquisition investment of approximately $7.5 billion at current exchange rates.

At December 31, 2008, the book value of our investment in Australia Pacific LNG (APLNG) was $5.4 billion. Our 50 percent share of the historical cost basis net assets of APLNG on its books under U.S. generally accepted accounting principles (GAAP) was $380 million, resulting in a basis difference of $5 billion on our books. The amortizable portion of the basis difference, approximately $3.5 billion associated with properties, plants and equipment, has been allocated on a relative fair value basis to the 62 individual exploration and production license areas owned by APLNG, most of which are not currently in production. Any future additional payments are expected to be allocated in a similar manner. Each exploration license area will periodically be reviewed for any indicators of potential impairment. As the joint venture begins producing natural gas from each license, we will begin amortizing the basis difference allocated to that license using the unit-of-production method. Included in net income for 2008 was after-tax expense of $7 million representing the amortization of this basis difference on currently producing licenses during the fourth quarter.

FCCL and WRB

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

FCCL s operating assets consist of the Foster Creek and Christina Lake steam-assisted gravity drainage bitumen projects, both located in the eastern flank of the Athabasca oil sands in northeastern Alberta. A subsidiary of EnCana is the operator and managing partner of FCCL. We are obligated to contribute $7.5 billion, plus accrued interest, to FCCL over a 10-year period beginning in 2007. For additional information on this obligation, see Note 13 Joint Venture Acquisition Obligation.

WRB s operating assets consist of the Wood River and Borger refineries, located in Roxana, Illinois, and Borger, Texas, respectively. As a result of our contribution of these two assets to WRB, a basis difference of $5 billion was created due to the fair value of the contributed assets recorded by WRB exceeding their historical book value. The difference is primarily amortized and recognized as a benefit evenly over a period of 25 years, which is the estimated remaining useful life of the refineries at the closing date. The basis difference at December 31, 2008, was approximately $4.6 billion. Equity earnings in 2008 and 2007 were increased by $246 million and $202 million, respectively, due to amortization of this basis difference. We are the operator and managing partner of WRB. EnCana is obligated to contribute $7.5 billion, plus accrued interest, to WRB over a 10-year period beginning in 2007. For the Wood River refinery, operating results are shared 50/50 starting upon formation. For the Borger refinery, we were entitled to 85 percent of the operating results in 2007, with our share decreasing to 65 percent in 2008, and 50 percent in all years thereafter.

LUKOIL

LUKOIL is an integrated energy company headquartered in Russia, with operations worldwide. Our ownership interest was 20 percent at December 31, 2006, 2007 and 2008, based on 851 million shares authorized and issued. For financial reporting under U.S. GAAP, treasury shares held by LUKOIL are not considered outstanding for determining our equity method ownership interest in LUKOIL. Our ownership interest, based on estimated shares outstanding, was 20.6 percent at December 31, 2006 and 2007, and 20.06 percent at December 31, 2008.

Because LUKOIL s accounting cycle close and preparation of U.S. 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, publicly available LUKOIL information, and other objective data. Once the difference between actual and estimated results is known, an adjustment is recorded. This estimate-to-actual adjustment will be a recurring component of future period results. Any difference between our estimate of fourth-quarter 2008 and the actual LUKOIL U.S. GAAP net income will be reported in our 2009 equity earnings.

Since the inception of our investment and through June 30, 2008, the market value of our investment in LUKOIL, based on the price of LUKOIL American Depositary Receipts (ADRs) on the London Stock Exchange, exceeded book value. However, as disclosed in our Form 10-Q for the quarterly period ended September 30, 2008, the price of LUKOIL ADRs declined significantly in the third quarter of 2008, closing the quarter at $58.80 per share. As a result, at September 30, 2008, the aggregate market value of our investment was less than book value by $2,861 million. At the time of the filing of our third-quarter 2008 Form 10-Q, we determined this decline in market value below book value did not meet the other-than-temporary impairment recognition guidance of APB Opinion No. 18, The Equity Method of Accounting for Investments in Common Stock.

The price of LUKOIL ADRs experienced significant further decline during the fourth quarter, and traded for most of the quarter and into early 2009 in the general range of $25 to $40 per share. The ADR price ended the year at $32.05 per share, or 45 percent lower than the September 30, 2008, price. This resulted in a December 31, 2008, market value of our investment of $5,452 million, or 58 percent lower than our book value. Based on a review of the facts and circumstances surrounding this further decline in the market value of our investment during the fourth quarter, we concluded that an impairment of our investment was necessary. In reaching this conclusion, we considered the increased length of time market value has been below book value and the severity of the decline in market value to be important factors. In combination, these two items caused us to conclude that the decline was other than temporary.

Accordingly, we recorded a noncash $7,410 million, before- and after-tax impairment, in our fourth-quarter 2008 results. This impairment had the effect of reducing our book value to $5,452 million, based on the market value of LUKOIL ADRs on December 31, 2008.

At December 31, 2008, the book value of our ordinary share investment in LUKOIL was $5,452 million. Our 20 percent share of the net assets of LUKOIL was estimated to be $10,350 million. This negative basis difference of $4,898 million will primarily be amortized on a straight-line basis over a 22-year useful life as an increase to equity earnings. Equity earnings in 2008, 2007 and 2006 were reduced $88 million, $77 million and $43 million, respectively, due to amortization of the positive basis difference that existed prior to the year-end investment impairment.

NMNG

NMNG is a joint venture with LUKOIL, created in June 2005, to develop resources in the northern part of Russia s Timan-Pechora province. We have a 30 percent direct ownership interest with a 50 percent governance interest. NMNG is working to develop the Yuzhno Khylchuyu (YK) field, which achieved initial production in June 2008. 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. We use the equity method of accounting for this joint venture.

At December 31, 2008, the book value of our investment in NMNG was $1,751 million. When our interest was acquired in 2005, the difference between our acquisition cost and the net asset value of our 30 percent interest was approximately $200 million. Since our initial investment, we have added $127 million of capitalized interest to our basis difference. For the portion of the basis difference that is amortizable, the basis difference is primarily amortized on a unit-of-production basis. Equity earnings for 2006 and 2007 were increased by $1 million and $30 million, respectively, due to amortization of the basis difference. Equity earnings for 2008 were decreased by $47 million. The change from an increase to a decrease of equity earnings reflects the change in the mix of producing properties.

DCP Midstream

DCP Midstream is a joint venture between ConocoPhillips and Spectra Energy, whereby each party owns a 50 percent interest. DCP Midstream owns and operates gas plants, gathering systems, storage facilities and fractionation plants.

At December 31, 2008, the book value of our investment in DCP Midstream was $838 million. Our 50 percent share of the net assets of DCP Midstream was $825 million. This difference of $13 million is being amortized on a straight-line basis through March 2015.

DCP Midstream markets a portion of its natural gas liquids to us and CPChem under a supply agreement that continues until December 31, 2014. This purchase commitment is on an if-produced, will-purchase basis and so 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. Natural gas liquids are purchased under this agreement at various published market index prices, less transportation and fractionation fees.

CPChem

CPChem manufactures and markets petrochemicals and plastics. At December 31, 2008, the book value of our investment in CPChem was $2,186 million. Our 50 percent share of the total net assets of CPChem was $2,073 million. This difference of $113 million is being amortized on a straight-line basis through 2020. We have multiple supply and purchase agreements in place with CPChem, ranging in initial terms from one to 99 years, with extension options. These agreements cover sales and purchases of refined products, solvents, and petrochemical and natural gas liquids feedstocks, as well as fuel oils and gases. Delivery quantities vary by product, and are generally on an if-produced, will-purchase basis. All products are purchased and sold under specified pricing formulas based on various published pricing indices, consistent with terms extended to third-party customers.

Loans to Related Parties

As part of our normal ongoing business operations and consistent with industry practice, we invest and enter into numerous agreements with other parties to pursue business opportunities, which share costs and apportion risks among the parties as governed by the agreements. Included in such activity are loans made to certain affiliated companies. Loans are recorded within Loans and advances related parties when cash is transferred to the affiliated company pursuant to a loan agreement. The loan balance will increase as interest is earned on the outstanding loan balance and will decrease as interest and principal payments are received. Interest is earned at the loan agreement s stated interest rate. Loans are assessed for impairment when events indicate the loan balance will not be fully recovered.

Significant loans to affiliated companies include the following:

We entered into a credit agreement with Freeport LNG, whereby we provided loan financing of approximately $650 million, excluding accrued interest, for the construction of an LNG facility which became operational in June 2008. The loan was converted from a construction loan to a term loan in August 2008, and Freeport started making repayments in September 2008. At the time of the loan conversion in August, it consisted of $650 million of principal and $124 million of accrued interest. As of December 31, 2008, the outstanding loan balance was $757 million.

We had an obligation to provide loan financing to Varandey Terminal Company for 30 percent of the costs of the terminal expansion. Terminal construction was completed in June 2008, and the final loan amount was $275 million at December 2008 exchange rates, excluding accrued interest. Although repayments were not required to start until May 2010, Varandey used available cash to repay $12 million of interest in the second half of 2008. The outstanding accrued interest at December 31, 2008, was $38 million at December exchange rates.

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. (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 in 2011, all project loan facilities, including the ConocoPhillips loan facilities, will become nonrecourse to the project participants. At December 31, 2008, Qatargas 3 had $3.0 billion outstanding under all the loan facilities, of which ConocoPhillips provided $835 million, and an additional $76 million of accrued interest.

Table of Contents

Note 8 Properties, Plants and Equipment

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

	Millions of Dollars					
		2008			2007	
	Gross PP&E	Accum. DD&A	Net PP&E	Gross PP&E	Accum. DD&A	Net PP&E
E&P	**$ 102,591**	**35,375**	**67,216**	102,550	30,701	71,849
Midstream	**120**	**70**	**50**	267	103	164
R&M	**21,116**	**5,962**	**15,154**	19,926	4,733	15,193
LUKOIL Investment						
Chemicals						
Emerging Businesses	**1,056**	**293**	**763**	1,204	138	1,066
Corporate and Other	**1,561**	**797**	**764**	1,414	683	731
	$ 126,444	**42,497**	**83,947**	125,361	36,358	89,003

Suspended Wells

The following table reflects the net changes in suspended exploratory well costs during 2008, 2007 and 2006:

	Millions of Dollars		
	2008	2007	2006
Beginning balance at January 1	**$ 589**	537	339
Additions pending the determination of proved reserves	**160**	157	225
Reclassifications to proved properties	**(37)**	(58)	(8)
Sales of suspended well investment	**(10)**	(22)	
Charged to dry hole expense	**(42)**	(25)	(19)
Ending balance at December 31	**$ 660**	589*	537*

* *Includes $7 million and $29 million related to assets held for sale in 2007 and 2006, respectively. See Note 6 Assets Held for Sale, for additional information.*

The following table provides an aging of suspended well balances at December 31, 2008, 2007 and 2006:

	Millions of Dollars		
	2008	2007	2006
Exploratory well costs capitalized for a period of one year or less	**$ 182**	153	225
Exploratory well costs capitalized for a period greater than one year	**478**	436	312
Ending balance	**$ 660**	589	537
Number of projects that have exploratory well costs that have been capitalized for a period greater than one year	**31**	35	22

The following table provides a further aging of those exploratory well costs that have been capitalized for more than one year since the completion of drilling as of December 31, 2008:

	Millions of Dollars							
		Suspended Since						
Project	Total	2007	2006	2005	2004	2003	2002	2001
Aktote Kazakhstan *(2)*	$ 18				7	11		
Alpine satellite Alaska *(2)*	23						23	
Caldita/Barossa Australia *(1)*	77		44	33				
Clair U.K. *(2)*	43	28	15					
Harrison U.K. *(2)*	14	14						
Humphrey U.K. *(2)*	10		10					
Jasmine U.K. *(2)*	22		22					
Kairan Kazakhstan *(2)*	27	14			13			
Kashagan Kazakhstan *(1)*	24	15						9
Malikai Malaysia *(2)*	48		16	21	11			
Petai Malaysia *(1)*	20	11		9				
Plataforma Deltana Venezuela *(2)*	21			6	15			
Surmont Canada *(1)*	17	9	6		2			
Su Tu Trang Vietnam *(1)*	32		16	8		8		
Uge Nigeria *(2)*	14			14				
West Sak Alaska *(2)*	10		6	3	1			
Fifteen projects of less than $10 million each *(1)(2)*	58	10	38	4		2	4	
Total of 31 projects	$ 478	101	173	98	49	21	27	9

(1) Additional appraisal wells planned.

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

Note 9 Goodwill and Intangibles

Changes in the carrying amount of goodwill are as follows:

	Millions of Dollars		
	E&P	R&M	Total
Balance at December 31, 2006	$ 27,712	3,776	31,488
Goodwill allocated to expropriated assets	(1,925)		(1,925)
Acquired (Burlington Resources adjustment)	172		172
Goodwill allocated to assets held for sale or sold	(191)	(3)	(194)

Tax and other adjustments	(199)	(6)	(205)
Balance at December 31, 2007	25,569	3,767	29,336
Goodwill impairment	**(25,443)**		**(25,443)**
Goodwill allocated to assets held for sale or sold	**(148)**		**(148)**
Tax and other adjustments	**22**	**11**	**33**
Balance at December 31, 2008	**$**	**3,778**	**3,778**

Goodwill Impairment

Goodwill is subject to annual reviews for impairment based on a two-step accounting test. The first step is to compare the estimated fair value of any reporting units within the company that have recorded goodwill with the recorded net book value (including the goodwill) of the reporting unit. If the estimated fair value of the reporting unit is higher than the recorded net book value, no impairment is deemed to exist and no further testing is required. If, however, the estimated fair value of the reporting unit is below the recorded net book value, then a second step must be performed to determine the goodwill impairment required, if any. In this second step, the estimated fair value from the first step is used as the purchase price in a hypothetical acquisition of the reporting unit. Purchase business combination accounting rules are followed to determine a hypothetical purchase price allocation to the reporting unit s assets and liabilities. The residual amount of goodwill that results from this hypothetical purchase price allocation is compared to the recorded amount of goodwill for the reporting unit, and the recorded amount is written down to the hypothetical amount, if lower.

We perform our annual goodwill impairment review in the fourth quarter of each year. During the fourth quarter of 2008, there were severe disruptions in the credit markets and reductions in global economic activity which had significant adverse impacts on stock markets and oil-and-gas-related commodity prices, both of which contributed to a significant decline in our company s stock price and corresponding market capitalization. For most of the fourth quarter, our market capitalization value was significantly below the recorded net book value of our balance sheet, including goodwill.

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 annual 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. A key component of these fair value determinations is a reconciliation of the sum of these net present value calculations to our market capitalization. We use an average of our market capitalization over the 30 calendar days preceding the impairment testing date as being more reflective of our stock price trend than a single day, point-in-time market price. Because, in our judgment, Worldwide E&P is considered to have a higher valuation volatility than Worldwide R&M, the long-term free cash flow growth rate implied from this reconciliation to our recent average market capitalization is applied to the Worldwide E&P net present value calculation.

The accounting principles regarding goodwill acknowledge that the observed market prices of individual trades of a company s stock (and thus its computed market capitalization) may not be representative of the fair value of the company as a whole. Substantial value may arise from the ability to take advantage of synergies and other benefits that flow from control over another entity. Consequently, measuring the fair value of a collection of assets and liabilities that operate together in a controlled entity is different from measuring the fair value of that entity s individual common stock. In most industries, including ours, an acquiring entity typically is willing to pay more for equity securities that give it a controlling interest than an investor would pay for a number of equity securities representing less than a controlling interest. Therefore, once the above net present value calculations have been determined, we also add a control premium to the calculations. This control premium is judgmental and is based on observed acquisitions in our industry. The resultant fair values calculated for the reporting units are then compared to observable metrics on large mergers and acquisitions in our industry to determine whether those valuations, in our judgment, appear reasonable.

After determining the fair values of our various reporting units as of December 31, 2008, it was determined that our Worldwide R&M reporting unit passed the first step of the goodwill impairment test, while our Worldwide E&P reporting unit did not pass the first step. As described above, the second step of the goodwill impairment test uses the estimated fair value of Worldwide E&P from the first step as the purchase price in a hypothetical acquisition of the reporting unit. The significant hypothetical purchase price allocation adjustments made to the assets and liabilities of Worldwide E&P in this second step calculation were in the areas of:

- Adjusting the carrying value of major equity method investments to their estimated fair values.
- Adjusting the carrying value of properties, plants and equipment (PP&E) to the estimated aggregate fair value of all oil and gas property interests.

Recalculating deferred income taxes under FASB Statement No. 109, Accounting for Income Taxes, after considering the likely tax basis a hypothetical buyer would have in the assets and liabilities.

When determining the above adjustment for the estimated aggregate fair value of PP&E, it was noted that in order for any residual purchase price to be allocated to goodwill, the purchase price assigned to PP&E would have to be well below the value of the PP&E implied by recently-observed metrics from other sales of major oil and gas properties. Based on the above analysis, we concluded that a $25.4 billion before- and after-tax noncash impairment of the entire amount of recorded goodwill for the Worldwide E&P reporting unit was required. This impairment was recorded in the fourth quarter of 2008.

Venezuela Expropriation

In the second quarter of 2007, we recorded a noncash impairment related to the expropriation of our oil interests in Venezuela. The impairment included $1,925 million before- and after-tax of goodwill allocated to the expropriation event. For additional information, see the Expropriated Assets section of Note 10 Impairments.

Intangible Assets

Information on the carrying value of intangible assets follows:

	Millions of Dollars		
	Gross Carrying Amount	Accumulated Amortization	Net Carrying Amount
Amortized Intangible Assets			
Balance at December 31, 2008			
Technology related	**$ 120**	**(60)**	**60**
Refinery air permits	**14**	**(10)**	**4**
Contract based	**116**	**(81)**	**35**
Other	**36**	**(27)**	**9**
	$ 286	**(178)**	**108**
Balance at December 31, 2007			
Technology related	$ 145	(60)	85
Refinery air permits	14	(8)	6
Contract based	124	(62)	62
Other	37	(25)	12
	$ 320	(155)	165
Indefinite-Lived Intangible Assets			
Balance at December 31, 2008			
Trade names and trademarks	**$ 494**		
Refinery air and operating permits	**244**		
	$ 738		
Balance at December 31, 2007			
Trade names and trademarks	$ 494		

Refinery air and operating permits		237
	$	731

Table of Contents

In addition to the above amounts, we had $2 million of intangibles classified as held for sale at year-end 2008 and 2007.

Amortization expense related to the intangible assets above for the years ended December 31, 2008 and 2007, was $35 million and $54 million, respectively. Estimated amortization expense for 2009 is approximately $29 million. It is expected to be approximately $20 million per year during 2010 and 2011, and approximately $7 million per year during 2012 and 2013.

Note 10 Impairments

Goodwill

See the Goodwill Impairment section of Note 9 Goodwill and Intangibles, for information on the complete impairment of our E&P segment goodwill.

LUKOIL

See the LUKOIL section of Note 7 Investments, Loans and Long-Term Receivables, for information on the impairment of our LUKOIL investment.

Expropriated Assets

On January 31, 2007, Venezuela s National Assembly passed a law allowing the president of Venezuela to pass laws on certain matters by decree. On February 26, 2007, the president of Venezuela issued a decree (the Nationalization Decree) mandating the termination of the then-existing structures related to our heavy oil ventures and oil production risk contracts and the transfer of all rights relating to our heavy oil ventures and oil production risk contracts to joint ventures (*empresas mixtas*) that will be controlled by the Venezuelan national oil company or its subsidiaries.

On June 26, 2007, we announced we had been unable to reach agreement with respect to our migration to an *empresa mixta* structure mandated by the Nationalization Decree. In response, Petróleos de Venezuela S.A. (PDVSA) or its affiliates directly assumed the activities associated with ConocoPhillips interests in the Petrozuata and Hamaca heavy oil ventures and the offshore Corocoro oil development project. Based on Venezuelan statements that the expropriation of our oil interests in Venezuela occurred on June 26, 2007, management determined such expropriation required a complete impairment, under U.S. generally accepted accounting principles, of our investments in the Petrozuata and Hamaca heavy oil ventures and the offshore Corocoro oil development project. Accordingly, we recorded a noncash impairment, including allocable goodwill, of $4,588 million before-tax ($4,512 million after-tax) in the second quarter of 2007.

The impairment included equity method investments and properties, plants and equipment. Also, this expropriation of our oil interests is viewed as a partial disposition of our Worldwide E&P reporting unit and, under the guidance in SFAS No. 142, Goodwill and Other Intangible Assets, required an allocation of goodwill to the expropriation event. The amount of goodwill impaired as a result of this allocation was $1,925 million.

We filed a request for international arbitration on November 2, 2007, with the International Centre for Settlement of Investment Disputes (ICSID), an arm of the World Bank. The request was registered by ICSID on December 13, 2007. The tribunal of three arbitrators is constituted, and the arbitration proceeding is under way.

We believe the value of our expropriated Venezuelan oil operations substantially exceeds the historical cost-based carrying value plus goodwill allocable to those operations. However, U.S. generally accepted accounting principles require a claim that is the subject of litigation be presumed to not be probable of realization. In addition, the timing of any negotiated or arbitrated settlement is not known at this time, but we anticipate it could take years. Accordingly, any compensation for our expropriated assets was not considered

Table of Contents

when making the impairment determination, since to do so could result in the recognition of compensation for the expropriation prior to its realization.

Other Impairments

During 2008, 2007 and 2006, we recognized the following before-tax impairment charges, excluding the goodwill, LUKOIL investment and expropriated assets impairments noted above:

	Millions of Dollars		
	2008	2007	2006
E&P			
United States	$ **620**	73	55
International	**173**	398	160
R&M			
United States	**534**	66	255
International	**181**	25	213
Increase in fair value of previously impaired assets		(128)	
Emerging Businesses	**130**		
Corporate	**48**	8	
	$ **1,686**	442	683

As a result of the economic downturn in the fourth quarter of 2008, the outlook for crude oil and natural gas prices, refining margins, and power spreads sharply deteriorated. In addition, current project economics in our E&P segment resulted in revised capital spending plans. Because of these factors, certain E&P, R&M and Emerging Businesses properties no longer passed the undiscounted cash flow tests required by SFAS No. 144, Accounting for the Impairment or Disposal of Long-Lived Assets, and thus had to be written down to fair value. Consequently, we recorded property impairments of approximately $1,480 million, primarily consisting of:

- $712 million for producing fields in the U.S. Lower 48 and Canada.
- $625 million for a refinery in the United States and one in Europe.
- $130 million for a U.S. power generation facility.

Also during 2008, we recorded property impairments of:

- $63 million due to increased asset retirement obligations for properties at the end of their economic life, primarily for certain fields located in the North Sea.
- $61 million associated with planned asset dispositions consisting mainly of $52 million for downstream assets in the United States.
- $48 million for vacant office buildings in the United States.
- $30 million for cancelled capital projects, primarily in our R&M segment.

Table of Contents

During 2007, we recorded property impairments of $257 million associated with planned asset dispositions, comprised of $187 million of impairments in our E&P segment and $70 million in our R&M segment. In addition to impairments resulting from planned asset dispositions, the E&P segment recorded property impairments in 2007 resulting from:

Increased asset retirement obligations for properties at the end of their economic life for certain fields, primarily located in the North Sea, totaling $175 million.

Downward reserve revisions and higher projected operating costs for fields in the United States, Canada and the United Kingdom, totaling $80 million.

An abandoned project in Alaska resulting from increased taxes, totaling $28 million.

In addition to impairments resulting from planned asset dispositions, the R&M segment recorded property impairments in 2007 of $21 million associated with various terminals and pipelines, primarily in the United States.

In addition and in accordance with SFAS No. 144, Accounting for the Impairment or Disposal of Long-Lived Assets, we reported a $128 million benefit in 2007 for the subsequent increase in the fair value of certain assets impaired in the prior year, primarily to reflect finalized sales agreements. This gain was included in the Impairments Other line of the consolidated statement of operations.

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

Note 11 Asset Retirement Obligations and Accrued Environmental Costs

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

		Millions of Dollars	
		2008	2007
Asset retirement obligations	$	**6,615**	6,613
Accrued environmental costs		**979**	1,089
Total asset retirement obligations and accrued environmental costs		**7,594**	7,702
Asset retirement obligations and accrued environmental costs due within one year*		**(431)**	(441)
Long-term asset retirement obligations and accrued environmental costs	$	**7,163**	7,261

* *Classified as a current liability on the balance sheet, under the caption Other accruals. Includes $14 million and $23 million related to assets held for sale in*

2008 and 2007, respectively. See Note 6 Assets Held for Sale, for additional information.

Asset Retirement Obligations

SFAS No. 143 requires entities to record the fair value of a liability for an asset retirement obligation when it is incurred (typically when the asset is installed at the production location). When the liability is initially recorded, the entity capitalizes the cost by increasing the carrying amount of the related properties, plants and equipment. Over time, the liability increases for the change in its present value, while the capitalized cost depreciates over the useful life of the related asset.

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

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

During 2008 and 2007, our overall asset retirement obligation changed as follows:

	Millions of Dollars	
	2008	2007
Balance at January 1	$ **6,613**	5,402
Accretion of discount	**389**	310
New obligations	**123**	76
Changes in estimates of existing obligations	**994**	843
Spending on existing obligations	**(217)**	(146)
Property dispositions	**(115)**	(259)*
Foreign currency translation	**(1,172)**	395
Expropriation of Venezuela assets		(8)
Balance at December 31	$ **6,615**	6,613

* *Includes $45 million associated with assets contributed to an equity affiliate.*

Accrued Environmental Costs

Total environmental accruals at December 31, 2008 and 2007, were $979 million and $1,089 million, respectively. The 2008 decrease in total accrued environmental costs is due to payments during the year on accrued environmental costs exceeding new accruals, accrual adjustments and accretion.

We had accrued environmental costs of $652 million and $740 million at December 31, 2008 and 2007, respectively, primarily related to cleanup at domestic refineries and underground storage tanks at U.S. service stations, and remediation activities required by Canada and the state of Alaska at exploration and production sites. We had also accrued in Corporate and Other $234 million and $255 million of environmental costs associated with nonoperator sites at December 31, 2008 and 2007, respectively. In addition, $93 million and $94 million were included at December 31, 2008 and 2007, respectively, where the company has been named a potentially responsible party under the Federal Comprehensive Environmental Response, Compensation and Liability Act, or similar state laws. Accrued environmental liabilities will be paid over periods extending up to 30 years.

Because a large portion of the accrued environmental costs were acquired in various business combinations, they are discounted obligations. Expected expenditures for acquired environmental obligations are discounted using a weighted-average 5 percent discount factor, resulting in an accrued balance for acquired environmental liabilities of $729 million at December 31, 2008. The expected future undiscounted payments related to the portion of the accrued environmental costs that have been discounted are: $104 million in 2009, $101 million in 2010, $81 million in 2011, $79 million in 2012, $73 million in 2013, and $404 million for all future years after 2013.

Table of Contents

Note 12 Debt

Long-term debt at December 31 was:

	Millions of Dollars	
	2008	2007
9.875% Debentures due 2010	$ **150**	150
9.375% Notes due 2011	**328**	328
9.125% Debentures due 2021	**150**	150
8.75% Notes due 2010	**1,264**	1,264
8.20% Debentures due 2025	**150**	150
8.125% Notes due 2030	**600**	600
7.9% Debentures due 2047	**100**	100
7.8% Debentures due 2027	**300**	300
7.68% Notes due 2012	**30**	37
7.65% Debentures due 2023	**88**	88
7.625% Debentures due 2013	**100**	100
7.40% Notes due 2031	**500**	500
7.375% Debentures due 2029	**92**	92
7.25% Notes due 2031	**500**	500
7.20% Notes due 2031	**575**	575
7.125% Debentures due 2028		300
7% Debentures due 2029	**200**	200
6.95% Notes due 2029	**1,549**	1,549
6.875% Debentures due 2026	**67**	67
6.68% Notes due 2011	**400**	400
6.65% Debentures due 2018	**297**	297
6.50% Notes due 2011	**500**	500
6.40% Notes due 2011	**178**	178
6.375% Notes due 2009	**284**	284
6.35% Notes due 2011	**1,750**	1,750
5.951% Notes due 2037	**645**	645
5.95% Notes due 2036	**500**	500
5.90% Notes due 2032	**505**	505
5.90% Notes due 2038	**600**	
5.625% Notes due 2016	**1,250**	1,250
5.50% Notes due 2013	**750**	750
5.30% Notes due 2012	**350**	350
5.20% Notes due 2018	**500**	
4.75% Notes due 2012	**897**	897
4.40% Notes due 2013	**400**	
Commercial paper at 1.05% - 1.76% at year-end 2008 and 4.05% - 5.36% at year-end 2007	**6,933**	725
Floating Rate Five-Year Term Note due 2011 at 1.638% at year-end 2008 and 5.0625% at year-end 2007	**1,500**	3,000
Floating Rate Notes due 2009 at 4.42% at year-end 2008 and 5.34% at year-end 2007	**950**	950
Industrial Development Bonds due 2012 through 2038 at 0.93% - 5.75% at year-end 2008 and 3.50% - 5.75% at year-end 2007	**252**	252
Guarantee of savings plan bank loan payable due 2015 at 2.46% at year-end 2008 and 5.40% at year-end 2007	**140**	175

Note payable to Merey Sweeny, L.P. due 2020 at 7%*	**163**	172
Marine Terminal Revenue Refunding Bonds due 2031 at 0.40% - 1.00% at year-end 2008 and 3.40% - 3.51% at year-end 2007	**265**	265
Other	**36**	50
Debt at face value	**26,788**	20,945
Capitalized leases	**28**	54
Net unamortized premiums and discounts	**639**	688
Total debt	**27,455**	21,687
Short-term debt	**(370)**	(1,398)
Long-term debt	**$ 27,085**	20,289

* *Related party.*

Table of Contents

Maturities of long-term borrowings, inclusive of net unamortized premiums and discounts, in 2009 through 2013 are: $370 million, $1,496 million, $4,714 million, $8,221 million and $1,290 million, respectively. At December 31, 2008, we had classified $7,883 million of short-term debt as long-term debt, based on our ability and intent to refinance the obligation on a long-term basis under our revolving credit facilities and early 2009 issuance of long-term notes.

In January 2008, we reduced our Floating Rate Five-Year Term Note due 2011 from $3 billion to $2 billion, with a subsequent reduction in June 2008 to $1.5 billion. In March 2008, we redeemed our $300 million 7.125% Debentures due 2028 at a premium of $8 million, plus accrued interest.

In May 2008, we issued notes consisting of $400 million of 4.40% Notes due 2013, $500 million of 5.20% Notes due 2018 and $600 million of 5.90% Notes due 2038. The proceeds from the offering were used to reduce commercial paper and for general corporate purposes.

In October 2008, we issued approximately $4.9 billion of commercial paper to help fund our initial upfront payment to close on a transaction with Origin Energy to further enhance our long-term Australasian natural gas business. For additional information on the Origin transaction, see Note 7 Investments, Loans and Long-Term Receivables.

At December 31, 2008, we had two revolving credit facilities totaling $9.85 billion, consisting of a $7.35 billion facility, expiring in September 2012, and a $2.5 billion facility scheduled to expire September 2009 (terminated in early 2009, see below). The $7.35 billion facility was reduced from $7.5 billion during the third quarter of 2008 due to the bankruptcy of Lehman Commercial Paper Inc., one of the revolver participants. The $2.5 billion facility is a 364-day bank facility entered into during October 2008 to provide additional support of a temporary expansion of our commercial paper program. We expanded our commercial paper program to ensure adequate liquidity after the initial funding of our transaction with Origin Energy.

Our revolving credit facilities may be used as direct bank borrowings, as support for issuances of letters of credit totaling up to $750 million, as support for our commercial paper programs, or as support of up to $250 million on commercial paper issued by TransCanada Keystone Pipeline LP, a Keystone pipeline joint venture entity. The revolving credit 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 facility 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 ConocoPhillips, or by any of its consolidated subsidiaries.

We have two commercial paper programs: the ConocoPhillips $8.1 billion program, primarily a funding source for short-term working capital needs, and the ConocoPhillips Qatar Funding Ltd. $1.5 billion commercial paper program, which is used to fund commitments relating to the Qatargas 3 project. Commercial paper maturities are generally limited to 90 days. At December 31, 2008 and 2007, we had no direct outstanding borrowings under the revolving credit facilities, but $40 million and $41 million, respectively, in letters of credit had been issued. In addition, under both commercial paper programs, there was $6,933 million of commercial paper outstanding at December 31, 2008, compared with $725 million at December 31, 2007. Since we had $6,933 million of commercial paper outstanding, had issued $40 million of letters of credit and had up to a $250 million guarantee on commercial paper issued by Keystone, we had access to $2.6 billion in borrowing capacity under our revolving credit facilities at December 31, 2008.

Credit facility borrowings may bear interest at a margin above rates offered by certain designated banks in the London interbank market or at a margin above the overnight federal funds rate or prime rates offered by certain designated banks in the United States. The agreements call for commitment fees on available, but unused, amounts. The agreements also contain early termination rights if our current directors or their approved successors cease to be a majority of the Board of Directors.

Table of Contents

In early 2009, we issued $1.5 billion of 4.75% Notes due 2014, $2.25 billion of 5.75% Notes due 2019, and $2.25 billion of 6.50% Notes due 2039. The proceeds of the notes were primarily used to reduce outstanding commercial paper balances. Under the terms of the $2.5 billion, 364-day revolving credit facility noted above, the receipt of the proceeds from this bond offering terminated this revolving credit facility.

Note 13 Joint Venture Acquisition Obligation

On January 3, 2007, we closed on a business venture with EnCana Corporation. As a part of the transaction, we are obligated to contribute $7.5 billion, plus interest, over a 10-year period, beginning in 2007, to the upstream business venture, FCCL Oil Sands Partnership, formed as a result of the transaction. An initial cash contribution of $188 million was made upon closing in January of 2007, and was included in the Capital expenditures and investments line on our consolidated statement of cash flows.

Quarterly principal and interest payments of $237 million began in the second quarter of 2007, and will continue until the balance is paid. Of the principal obligation amount, approximately $625 million was short-term and was included in the Accounts payable related parties line on our December 31, 2008, consolidated balance sheet. The principal portion of these payments, which totaled $593 million in 2008, was included in the Other line in the financing activities section of our consolidated statement of cash flows. Interest accrues at a fixed annual rate of 5.3 percent on the unpaid principal balance. Fifty percent of the quarterly interest payments is reflected as an additional capital contribution and is included in the Capital expenditures and investments line on our consolidated statement of cash flows.

Note 14 Guarantees

At December 31, 2008, we were liable for certain contingent obligations under various contractual arrangements as described below. We recognize a liability, at inception, for the fair value of our obligation as a guarantor for newly issued or modified guarantees. Unless the carrying amount of the liability is noted below, we have not recognized a liability either because the guarantees were issued prior to December 31, 2002, or because the fair value of the obligation is immaterial. In addition, unless otherwise stated we are not currently performing with any significance under the guarantee and expect future performance to be either immaterial or have only a remote chance of occurrence.

Construction Completion Guarantees

In December 2005, we issued a construction completion guarantee for 30 percent of the $4.0 billion in loan facilities of Qatargas 3, which will be used to construct an LNG train in Qatar. Of the $4.0 billion in loan facilities, ConocoPhillips has committed to provide $1.2 billion. The maximum potential amount of future payments to third-party lenders under the guarantee is estimated to be $850 million, which could become payable if the full debt financing is utilized and completion of the Qatargas 3 project is not achieved. The project financing will be nonrecourse to ConocoPhillips upon certified completion, currently expected in 2011. At December 31, 2008, the carrying value of the guarantee to the third-party lenders was $11 million. For additional information, see Note 7 Investments, Loans and Long-Term Receivables.

Guarantees of Joint Venture Debt

In June 2006, we issued a guarantee for 24 percent of the $2 billion in credit facilities of Rockies Express Pipeline LLC, which will be used to construct a natural gas pipeline across a portion of the United States. At December 31, 2008, Rockies Express had $1,561 million outstanding under the credit facilities, with our 24 percent guarantee equaling $375 million. The maximum potential amount of future payments to third-party lenders under the guarantee is estimated to be $480 million, which could

Table of Contents

become payable if the credit facilities are fully utilized and Rockies Express fails to meet its obligations under the credit agreement. In addition, we also have a guarantee for 24 percent of $600 million of Floating Rate Notes due 2009 issued by Rockies Express. It is anticipated final construction completion will be achieved in 2009, and refinancing will take place at that time, making the debt nonrecourse to ConocoPhillips. At December 31, 2008, the total carrying value of these guarantees to third-party lenders was $12 million.

In December 2007, we acquired a 50 percent equity interest in four Keystone pipeline entities (Keystone), to create a joint venture with TransCanada Corporation. Keystone is constructing a crude oil pipeline originating in Alberta, with delivery points in Illinois and Oklahoma. In December 2008, we provided a guarantee for up to $250 million of balances outstanding under a commercial paper program. This program was established by Keystone to provide funding for a portion of Keystone s construction costs attributable to our ownership interest in the project. Payment under the guarantee would be due in the event Keystone failed to repay principal and interest, when due, to short-term noteholders. The commercial paper program and our guarantee are expected to increase as funding needs increase during construction of the Keystone pipeline. Keystone s other owner will guarantee a similar, but separate, funding vehicle. Post-construction Keystone financing is anticipated to be nonrecourse to us. At December 31, 2008, $200 million was outstanding under the Keystone commercial paper program guaranteed by us.

At December 31, 2008, we had other guarantees outstanding for our portion of joint venture debt obligations, which have terms of up to 17 years. The maximum potential amount of future payments under the guarantees is approximately $90 million. Payment would be required if a joint venture defaults on its debt obligations.

Other Guarantees

In connection with certain planning and construction activities of the Keystone pipeline, we agreed to reimburse TransCanada with respect to a portion of guarantees issued by TransCanada for certain of Keystone s obligations to third parties. Our maximum potential amount of future payments associated with these guarantees is based on our ultimate ownership percentage in Keystone and is estimated to be $180 million, which could become payable if Keystone fails to meet its obligations and the obligations cannot otherwise be mitigated. Payments under the guarantees are contingent upon the partners not making necessary equity contributions into Keystone; therefore, it is considered unlikely payments would be required. All but $8 million of the guarantees will terminate after construction is completed, currently estimated to occur in 2010.

In October 2008, we elected to exercise an option to reduce our equity interest in Keystone from 50 percent to 20.01 percent. The change in equity will occur through a dilution mechanism, which is expected to gradually lower our ownership interest until it reaches 20.01 percent by the third quarter of 2009. At December 31, 2008, our ownership interest was 38.7 percent.

In addition to the above guarantee, in order to obtain long-term shipping commitments that would enable a pipeline expansion starting at Hardisty, Alberta, and extending to near Port Arthur, Texas, the Keystone owners executed an agreement in July 2008 to guarantee Keystone s obligations under its agreement to provide transportation at a specified price for certain shippers to the Gulf Coast. Although our guarantee is for 50 percent of these obligations, TransCanada has agreed to reimburse us for amounts we pay in excess of our ownership percentage in Keystone. Our maximum potential amount of future payments, or cost of volume delivery, under this guarantee, after such reimbursement, is estimated to be $220 million ($550 million before reimbursement) based on a full 20-year term of the shipping commitments, which could become payable if Keystone fails to meet its obligations under the agreements and the obligations cannot otherwise be mitigated. Future payments are considered unlikely, as the payments, or cost of volume delivery, are contingent upon Keystone defaulting on its obligation to construct the pipeline in accordance with the terms of the agreement.

We have other guarantees with maximum future potential payment amounts totaling $520 million, which consist primarily of dealer and jobber loan guarantees to support our marketing business, guarantees to fund the short-term cash liquidity deficits of certain joint ventures, a guarantee of minimum charter revenue for two LNG vessels, one small construction completion guarantee, guarantees relating to the startup of a refining joint venture, guarantees of the lease payment obligations of a joint venture, and guarantees of the residual value of leased corporate aircraft. These guarantees generally extend up to 16 years or life of the venture.

Indemnifications

Over the years, we have entered into various agreements to sell ownership interests in certain corporations and joint ventures and have sold several assets, including downstream and midstream assets, certain exploration and production assets, and downstream retail and wholesale sites that gave rise to qualifying indemnifications. Agreements associated with these sales include indemnifications for taxes, environmental liabilities, permits and licenses, employee claims, real estate indemnity against tenant defaults, and litigation. The terms of these indemnifications vary greatly. The majority of these indemnifications are related to environmental issues, the term is generally indefinite and the maximum amount of future payments is generally unlimited. The carrying amount recorded for these indemnifications at December 31, 2008, was $427 million. We amortize the indemnification liability over the relevant time period, if one exists, based on the facts and circumstances surrounding each type of indemnity. In cases where the indemnification term is indefinite, we will reverse the liability when we have information the liability is essentially relieved or amortize the liability over an appropriate time period as the fair value of our indemnification exposure declines. Although it is reasonably possible future payments may exceed amounts recorded, due to the nature of the indemnifications, it is not possible to make a reasonable estimate of the maximum potential amount of future payments. Included in the carrying amount recorded were $239 million of environmental accruals for known contamination that is included in asset retirement obligations and accrued environmental costs at December 31, 2008. For additional information about environmental liabilities, see Note 15 Contingencies and Commitments.

Note 15 Contingencies and Commitments

In the case of all known non-income-tax-related contingencies, we accrue a liability when the loss is probable and the amount is reasonably estimable. If a range of amounts can be reasonably estimated and no amount within the range is a better estimate than any other amount, then the minimum of the range is accrued. We do not reduce these liabilities for potential insurance or third-party recoveries. If applicable, we accrue receivables for probable insurance or other third-party recoveries. In the case of income-tax-related contingencies, we adopted FIN 48, effective January 1, 2007. FIN 48 requires a cumulative probability-weighted loss accrual in cases where sustaining a tax position is less than certain. See Note 21 Income Taxes, for additional information about income-tax-related contingencies.

Based on currently available information, we believe 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 consolidated financial statements. As we learn new facts concerning contingencies, we reassess our position both with respect to accrued liabilities and other potential exposures. Estimates that are particularly sensitive to future changes include contingent liabilities recorded for environmental remediation, tax and legal matters. Estimated future environmental remediation costs are subject to change due to such factors as the uncertain magnitude of cleanup costs, the unknown time and extent of such remedial actions that may be required, and the determination of our liability in proportion to that of other responsible parties. Estimated future costs related to tax and legal matters are subject to change as events evolve and as additional information becomes available during the administrative and litigation processes.

Environmental

We are subject to federal, state and local environmental laws and regulations. These may result in obligations to remove or mitigate the effects on the environment of the placement, storage, disposal or release of certain chemical, mineral and petroleum substances at various sites. When we prepare our consolidated financial statements, we record accruals for environmental liabilities based on management s best estimates, using all information that is available at the time. We measure estimates and base liabilities on currently available facts, existing technology, and presently enacted laws and regulations, taking into account stakeholder and business considerations. When measuring environmental liabilities, we also consider our prior experience in remediation of contaminated sites, other companies cleanup experience, and data released by the U.S. Environmental Protection Agency (EPA) or other organizations. We consider unasserted claims in our determination of environmental liabilities and we accrue them in the period they are both probable and reasonably estimable.

Although liability of those potentially responsible for environmental remediation costs is generally joint and several for federal sites and frequently so for state sites, we are usually only one of many companies cited at a particular site. Due to the joint and several liabilities, we could be responsible for all of the cleanup costs related to any site at which we have been designated as a potentially responsible party. If we were solely responsible, the costs, in some cases, could be material to our, or one of our segments , results of operations, capital resources or liquidity. However, settlements and costs incurred in matters that previously have been resolved have not been material to our results of operations or financial condition. We have been successful to date in sharing cleanup costs with other financially sound companies. Many of the sites at which we are potentially responsible are still under investigation by the EPA or the state agencies concerned. Prior to actual cleanup, those potentially responsible normally assess the site conditions, apportion responsibility and determine the appropriate remediation. In some instances, we may have no liability or may attain a settlement of liability. Where it appears that other potentially responsible parties may be financially unable to bear their proportional share, we consider this inability in estimating our potential liability, and we adjust our accruals accordingly.

As a result of various acquisitions in the past, we assumed certain environmental obligations. Some of these environmental obligations are mitigated by indemnifications made by others for our benefit and some of the indemnifications are subject to dollar limits and time limits. We have not recorded accruals for any potential contingent liabilities that we expect to be funded by the prior owners under these indemnifications.

We are currently participating in environmental assessments and cleanups at numerous federal Superfund and comparable state sites. After an assessment of environmental exposures for cleanup and other costs, we make accruals on an undiscounted basis (except those acquired in a purchase business combination, which we record on a discounted basis) for planned investigation and remediation activities for sites where it is probable that future costs will be incurred and these costs can be reasonably estimated. We have not reduced these accruals for possible insurance recoveries. In the future, we may be involved in additional environmental assessments, cleanups and proceedings. See Note 11 Asset Retirement Obligations and Accrued Environmental Costs, for a summary of our accrued environmental liabilities.

Legal Proceedings

Our legal organization applies its knowledge, experience, and professional judgment to the specific characteristics of our cases, employing a litigation management process to manage and monitor the legal proceedings against us. Our process facilitates the early evaluation and quantification of potential exposures in individual cases. This process also enables us to track those cases which have been scheduled for trial, as well as the pace of settlement discussions in individual matters. Based on professional judgment and experience in using these litigation management tools and available information about current developments in all our cases, our legal organization believes there is a remote likelihood future costs related to known contingent liability exposures will exceed current accruals by an amount that would have a material adverse impact on our consolidated financial statements.

Other Contingencies

We have contingent liabilities resulting from throughput agreements with pipeline and processing companies not associated with financing arrangements. Under these agreements, we may be required to provide any such company with additional funds through advances and penalties for fees related to throughput capacity not utilized. In addition, at December 31, 2008, we had performance obligations secured by letters of credit of $1,950 million (of which $40 million was issued under the provisions of our revolving credit facility, and the remainder was issued as direct bank letters of credit) related to various purchase commitments for materials, supplies, services and items of permanent investment incident to the ordinary conduct of business. See Note 10 Impairments, for additional information about expropriated assets in Venezuela and the contingencies related to receiving adequate compensation for our oil interests in Venezuela.

Long-Term Throughput Agreements and Take-or-Pay Agreements

We have certain throughput agreements and take-or-pay agreements that are in support of financing arrangements. The agreements typically provide for natural gas or crude oil transportation to be used in the ordinary course of the company s business. The aggregate amounts of estimated payments under these various agreements are: 2009 $62 million; 2010 $63 million; 2011 $63 million; 2012 $62 million; 2013 $62 million; and 2014 and after $152 million. Total payments under the agreements were $75 million in 2008, $67 million in 2007 and $66 million in 2006.

Note 16 Financial Instruments and Derivative Contracts

Derivative Instruments

We may use financial and commodity-based derivative contracts to manage exposures to fluctuations in foreign currency exchange rates, commodity prices, and interest rates, or to exploit market opportunities. Our use of derivative instruments is governed by an Authority Limitations document approved by our Board of Directors that prohibits the use of highly leveraged derivatives or derivative instruments without sufficient liquidity for comparable valuations. The Authority Limitations document also authorizes the Chief Operating Officer to establish the maximum Value at Risk (VaR) limits for the company, and compliance with these limits is monitored daily. The Chief Financial Officer monitors risks resulting from foreign currency exchange rates and interest rates and reports to the Chief Executive Officer. The Senior Vice President of Commercial monitors commodity price risk and reports to the Chief Operating Officer. The Commercial organization manages our commercial marketing, optimizes our commodity flows and positions, monitors related risks of our upstream and downstream businesses, and selectively takes price risk to add value.

SFAS No. 133, Accounting for Derivative Instruments and Hedging Activities, as amended (SFAS No. 133), requires companies to recognize all derivative instruments as either assets or liabilities on the balance sheet at fair value. Assets and liabilities resulting from derivative contracts open at December 31 were:

	Millions of Dollars	
	2008	2007
Derivative Assets		
Current	**$ 1,257**	453
Long-term	**182**	89
	$ 1,439	542
Derivative Liabilities		
Current	**$ 907**	493
Long-term	**129**	67
	$ 1,036	560

In the preceding table, the 2008 derivative assets appear net of $123 million of obligations to return cash collateral, and the 2008 derivative liabilities appear net of $332 million of rights to reclaim cash collateral. Collateral receivables and payables at December 31, 2007, were not material. The derivative assets and liabilities in the preceding table appear as prepaid expenses and other current assets, other assets, other accruals, or other liabilities and deferred credits on the balance sheet.

The accounting for changes in fair value (i.e., gains or losses) of a derivative instrument depends on whether it meets the qualifications for, and has been designated as, a SFAS No. 133 hedge, and the type of hedge. At this time, we are not using SFAS No. 133 hedge accounting. All gains and losses, realized or unrealized, from derivative contracts not designated as SFAS No. 133 hedges have been recognized in the consolidated statement of operations. Gains and losses from derivative contracts held for trading not directly related to our physical business, whether realized or unrealized, have been reported net in other income.

SFAS No. 133 also requires purchase and sales contracts for commodities that are readily convertible to cash (e.g., crude oil, natural gas, and gasoline) to be recorded on the balance sheet as derivatives unless the contracts are for quantities we expect to use or sell over a reasonable period in the normal course of business (the normal purchases and normal sales exception), among other requirements, and we have documented our intent to apply this exception. Except for contracts to buy or sell natural gas, we generally apply this exception to eligible purchase and sales contracts; however, we may elect not to apply this exception (e.g., when another derivative instrument will be used to mitigate the risk of the purchase or sale contract but hedge accounting will not be applied). When this occurs, both the purchase or sales contract and the derivative contract mitigating the resulting risk will be recorded on the balance sheet at fair value in accordance with the preceding paragraphs. Most of our contracts to buy or sell natural gas are recorded on the balance sheet as derivatives, except for certain long-term contracts to sell our natural gas production, for which we have elected the normal purchases and normal sales exception or which do not meet the SFAS No. 133 definition of a derivative.

Currency Exchange Rate Derivative Contracts We have foreign currency exchange rate risk resulting from international operations. We do not comprehensively hedge the exposure to currency rate changes, although we may choose to selectively hedge exposures to foreign currency rate risk. Examples include firm commitments for capital projects, certain local currency tax payments and dividends, net investment in a foreign subsidiary, short-term intercompany loans between subsidiaries operating in different countries, and cash returns from net investments in foreign affiliates to be remitted within the coming year.

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

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

- Balance physical systems. In addition to cash settlement prior to contract expiration, exchange traded futures contracts may also be settled by physical delivery of the commodity, providing another source of supply to meet our refinery requirements or marketing demand.
- Meet customer needs. Consistent with our policy to generally remain exposed to market prices, we use swap contracts to convert fixed-price sales contracts, which are often requested by natural gas and refined product consumers, to a floating market price.
- Manage the risk to our cash flows from price exposures on specific crude oil, natural gas, refined product and electric power transactions.
- Enable us to use the market knowledge gained from these activities to do a limited amount of trading not directly related to our physical business. For the years ended December 31, 2008, 2007 and 2006, the gains or losses from this activity were not material to our cash flows or net income.

Credit Risk

Our financial instruments that are potentially exposed to concentrations of credit risk consist primarily of cash equivalents, over-the-counter derivative contracts, and trade receivables. Our cash equivalents are placed in high-quality commercial paper, money market funds and time deposits with major international banks and financial institutions. The credit risk from our over-the-counter derivative contracts, such as forwards and swaps, derives from the counterparty to the transaction, typically a major bank or financial institution. We closely monitor these credit exposures against predetermined credit limits, including the continual exposure adjustments that result from market movements. Individual counterparty exposure is managed within these limits, and includes the use of cash-call margins when appropriate, thereby reducing the risk of significant nonperformance. We also use futures contracts, but futures have a negligible credit risk because they are traded on the New York Mercantile Exchange or the ICE Futures.

Our trade receivables result primarily from our petroleum operations and reflect a broad national and international customer base, which limits our exposure to concentrations of credit risk. The majority of these receivables have payment terms of 30 days or less, and we continually monitor this exposure and the creditworthiness of the counterparties. We do not generally require collateral to limit the exposure to loss; however, we will sometimes use letters of credit, prepayments, and master netting arrangements to mitigate credit risk with counterparties that both buy from and sell to us, as these agreements permit the amounts owed by us or owed to others to be offset against amounts due us.

Fair Values of Financial Instruments

We used the following methods and assumptions to estimate the fair value of financial instruments:

- Cash and cash equivalents: The carrying amount reported on the balance sheet approximates fair value.
- Accounts and notes receivable: The carrying amount reported on the balance sheet approximates fair value.
- Investment in LUKOIL shares: See Note 7 Investments, Loans and Long-Term Receivables, for a discussion of the carrying value and fair value of our investment in LUKOIL shares.
- Debt: The carrying amount of our floating-rate debt approximates fair value. The fair value of the fixed-rate debt is estimated based on quoted market prices.
- Fixed-rate 5.3 percent joint venture acquisition obligation: Fair value is estimated based on the net present value of the future cash flows, discounted at a year-end effective yield rate of 5.4 percent, based on yields of U.S. Treasury securities of similar average duration adjusted for our average credit risk spread and the amortizing nature of the obligation principal. See Note 13 Joint Venture Acquisition Obligation, for additional information.
- Swaps: Fair value is estimated based on forward market prices and approximates the exit price at year end. When forward market prices are not available, they are estimated using the forward prices of a similar commodity with adjustments for differences in quality or location.
- Futures: Fair values are based on quoted market prices obtained from the New York Mercantile Exchange, the ICE Futures, or other traded exchanges.
- Forward-exchange contracts: Fair value is estimated by comparing the contract rate to the forward rate in effect on December 31 and approximates the exit price at year end.

Table of Contents

Certain of our commodity derivative and financial instruments at December 31 were:

	Millions of Dollars			
	Carrying Amount		Fair Value	
	2008	2007	**2008**	2007
Financial assets				
Foreign currency derivatives	$ **160**	47	**160**	47
Commodity derivatives	**1,279**	495	**1,279**	495
Financial liabilities				
Total debt, excluding capital leases	**27,427**	21,633	**26,906**	23,101
Joint venture acquisition obligation	**6,294**	6,887	**6,294**	7,031
Foreign currency derivatives	**155**	29	**155**	29
Commodity derivatives	**881**	531	**881**	531

In the preceding table, 2008 derivative assets appear net of $123 million of obligations to return cash collateral, while 2008 derivative liabilities appear net of $332 million of rights to reclaim cash collateral. Collateral receivables and payables at December 31, 2007, were not material.

Note 17 Preferred Stock and Minority Interests

Preferred Stock

We have 500 million shares of preferred stock authorized, par value $.01 per share, none of which was issued or outstanding at December 31, 2008 or 2007.

Minority Interests

The minority interest owner in Ashford Energy Capital S.A. is entitled to a cumulative annual preferred return on its investment, consisting of 1.32 percent plus a three-month LIBOR rate set at the beginning of each quarter. The preferred return at December 31, 2008 and 2007, was 5.37 percent and 6.55 percent, respectively. At December 31, 2008 and 2007, the minority interest was $507 million and $508 million, respectively. Ashford Energy Capital S.A. is consolidated in our financial statements under the provisions of FIN 46(R) because we are the primary beneficiary. See Note 4 Variable Interest Entities (VIEs), for additional information.

The remaining minority interest amounts are primarily related to operating joint ventures we control. The largest of these, amounting to $580 million at December 31, 2008, and $648 million at December 31, 2007, relates to Darwin LNG, an operation located in Australia s Northern Territory.

Note 18 Preferred Share Purchase Rights

In 2002, our Board of Directors authorized and declared a dividend of one preferred share purchase right for each common share outstanding, and authorized and directed the issuance of one right per common share for any newly issued shares. The rights have certain anti-takeover effects. The rights will cause substantial dilution to a person or group that attempts to acquire ConocoPhillips on terms not approved by the Board of Directors. However, since the rights may either be redeemed or otherwise made inapplicable by ConocoPhillips prior to an acquiror obtaining beneficial ownership of 15 percent or more of ConocoPhillips common stock, the rights should not interfere with any merger or business combination approved by the Board of Directors prior to that occurrence. The rights, which expire June 30, 2012, will be exercisable only if a person or group acquires 15 percent or more of the company s common stock or commences a tender offer that would result in ownership of 15 percent or more of the common stock. Each right would entitle stockholders to buy one one-hundredth of a share of preferred stock at an exercise price of $300. If an acquiror obtains 15

Table of Contents

percent or more of ConocoPhillips common stock, then each right will be adjusted so that it will entitle the holder (other than the acquiror, whose rights will become void) to purchase, for the then exercise price, a number of shares of ConocoPhillips common stock equal in value to two times the exercise price of the right. In addition, the rights enable holders to purchase the stock of an acquiring company at a discount, depending on specific circumstances. We may redeem the rights in whole, but not in part, for one cent per right.

Note 19 Non-Mineral Leases

The company leases ocean transport vessels, tugboats, barges, pipelines, railcars, corporate aircraft, service stations, drilling equipment, computers, office buildings and other facilities and equipment. Certain leases include escalation clauses for adjusting rental payments to reflect changes in price indices, as well as renewal options and/or options to purchase the leased property for the fair market value at the end of the lease term. There are no significant restrictions imposed on us by the leasing agreements in regards to dividends, asset dispositions or borrowing ability. Leased assets under capital leases were not significant in any period presented.

At December 31, 2008, future minimum rental payments due under noncancelable leases were:

	Millions of Dollars
2009	$ 868
2010	731
2011	526
2012	453
2013	274
Remaining years	917
Total	3,769
Less income from subleases	(174)*
Net minimum operating lease payments	$ 3,595

* *Includes $76 million related to railcars subleased to Chevron Phillips Chemical Company LLC, a related party.*

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

	Millions of Dollars		
	2008	2007	2006
Total rentals*	**$ 1,033**	855	698
Less sublease rentals	**(125)**	(82)	(103)
	$ 908	773	595

* *Includes $22 million, $27 million and $29 million of contingent rentals in 2008, 2007 and 2006, respectively. Contingent rentals primarily are related to retail sites and refining equipment, and are based on volume of product sold or throughput.*

Table of Contents

Note 20 Employee Benefit Plans

Pension and Postretirement Plans

An analysis of the projected benefit obligations for our pension plans and accumulated benefit obligations for our postretirement health and life insurance plans follows:

	Millions of Dollars					
	Pension Benefits				Other Benefits	
	2008		2007		**2008**	2007
	U.S.	**Int l.**	U.S.	Int l.		
Change in Benefit Obligation						
Benefit obligation at January 1	$ **4,281**	**3,085**	4,113	3,087	**792**	778
Service cost	**186**	**100**	175	98	**11**	14
Interest cost	**247**	**198**	229	161	**47**	45
Plan participant contributions		**10**		10	**32**	28
Medicare Part D subsidy					**8**	6
Plan amendments	**8**		2	(68)	**(47)**	
Actuarial (gain) loss	**230**	**(180)**	109	(294)	**18**	(6)
Acquisitions						
Divestitures						
Benefits paid	**(332)**	**(117)**	(347)	(97)	**(85)**	(81)
Curtailment				1		
Recognition of termination benefits		**2**		1		
Foreign currency exchange rate change		**(791)**		186	**(8)**	8
Benefit obligation at December 31*	$ **4,620**	**2,307**	4,281	3,085	**768**	792
* *Accumulated benefit obligation portion of above at December 31:*	*$* ***4,022***	***1,946***	*3,666*	*2,550*		
Change in Fair Value of Plan Assets						
Fair value of plan assets at January 1	$ **3,138**	**2,601**	2,863	2,185	**3**	3
Acquisitions						
Divestitures						
Actual return on plan assets	**(840)**	**(342)**	237	169	**(1)**	
Company contributions	**407**	**170**	385	185	**45**	47
Plan participant contributions		**10**		10	**32**	28
Medicare Part D subsidy					**8**	6
Benefits paid	**(332)**	**(117)**	(347)	(97)	**(85)**	(81)
Foreign currency exchange rate change		**(594)**		149		
Fair value of plan assets at December 31:	$ **2,373**	**1,728**	3,138	2,601	**2**	3
Funded Status	$ **(2,247)**	**(579)**	(1,143)	(484)	**(766)**	(789)

Table of Contents

	Millions of Dollars					
	Pension Benefits				Other Benefits	
	2008		2007		**2008**	2007
	U.S.	**Int l.**	U.S.	Int l.		
Amounts Recognized in the Consolidated Balance Sheet at December 31						
Noncurrent assets	$	**33**		98		
Current liabilities	**(6)**	**(9)**	(6)	(9)	**(49)**	(50)
Noncurrent liabilities	**(2,241)**	**(603)**	(1,137)	(573)	**(717)**	(739)
Total recognized	$ **(2,247)**	**(579)**	(1,143)	(484)	**(766)**	(789)
Weighted-Average Assumptions Used to Determine Benefit Obligations at December 31						
Discount rate	**6.25%**	**6.00**	6.00	5.90	**6.30**	6.20
Rate of compensation increase	**4.00**	**4.20**	4.00	4.80		
Weighted-Average Assumptions Used to Determine Net Periodic Benefit Cost for Years Ended December 31						
Discount rate	**6.00%**	**5.90**	5.75	5.15	**6.20**	5.95
Expected return on plan assets	**7.00**	**6.80**	7.00	6.50	**7.00**	7.00
Rate of compensation increase	**4.00**	**4.80**	4.00	4.70		

For both U.S. and international pensions, the overall expected long-term rate of return is developed from the expected future return of each asset class, weighted by the expected allocation of pension assets to that asset class. We rely on a variety of independent market forecasts in developing the expected rate of return for each class of assets.

At December 31, 2007, all of our plans used a December 31 measurement date, except for a plan in the United Kingdom, which had a September 30 measurement date. To comply with the provisions of SFAS No. 158, Employers Accounting for Defined Benefit Pension and Other Postretirement Plans an amendment of FASB Statements No. 87, 88, 106, and 132(R), we changed the measurement date for the U.K. plan from September 30 to December 31 for our 2008 consolidated financial statements. We elected to implement the change by remeasuring the U.K. plan assets and obligations as of December 31, 2007. To implement the change in measurement date, we recognized the $10 million (net of tax) of net periodic pension cost incurred from October 1, 2007, to December 31, 2007, as an adjustment to 2008 beginning retained earnings.

Included in other comprehensive income at December 31 were the following before-tax amounts that had not been recognized in net periodic postretirement benefit cost:

	Millions of Dollars			
	Pension Benefits		Other Benefits	
	2008	2007	**2008**	2007

	U.S.	Int l.	U.S.	Int l.		
Unrecognized net actuarial loss (gain)	**$ 1,798**	**335**	587	123	**(149)**	(185)
Unrecognized prior service cost	**69**	**(22)**	71	(30)	**(43)**	15

123

Table of Contents

	Millions of Dollars					
	Pension Benefits				Other Benefits	
	2008		2007		**2008**	2007
	U.S.	**Int l.**	U.S.	Int l.		
Sources of Change in Other Comprehensive Income						
Net gain (loss) arising during the period	**$ (1,275)**	**(229)**	(72)	289	**(19)**	5
Amortization of (gain) loss included in income	**64**	**17**	62	48	**(17)**	(20)
Net gain (loss) during the period	**$ (1,211)**	**(212)**	(10)	337	**(36)**	(15)
Prior service cost arising during the period	**$ (8)**	**(9)**	(2)	67	**47**	
Amortization of prior service cost included in income	**10**	**1**	10	7	**11**	13
Net prior service cost during the period	**$ 2**	**(8)**	8	74	**58**	13

Amounts included in accumulated other comprehensive income at December 31, 2008, that are expected to be amortized into net periodic postretirement cost during 2009 are provided below:

	Millions of Dollars		
	Pension Benefits		Other Benefits
	U.S.	Int l.	
Unrecognized net actuarial loss (gain)	$ 186	33	(15)
Unrecognized prior service cost	11	1	9

For our tax-qualified pension plans with projected benefit obligations in excess of plan assets, the projected benefit obligation, the accumulated benefit obligation, and the fair value of plan assets were $6,092 million, $5,289 million, and $3,624 million at December 31, 2008, respectively, and $6,392 million, $5,417 million, and $5,056 million at December 31, 2007, respectively.

For our unfunded nonqualified key employee supplemental pension plans, the projected benefit obligation and the accumulated benefit obligation were $391 million and $334 million, respectively, at December 31, 2008, and were $390 million and $344 million, respectively, at December 31, 2007.

Table of Contents

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

	Millions of Dollars								
	Pension Benefits						Other Benefits		
	2008		2007		2006		**2008**	2007	2006
	U.S.	**Int l.**	U.S.	Int l.	U.S.	Int l.			
Components of Net Periodic Benefit Cost									
Service cost	**$ 186**	**85**	175	98	174	87	**11**	14	14
Interest cost	**247**	**170**	229	161	210	134	**47**	45	47
Expected return on plan assets	**(223)**	**(170)**	(204)	(147)	(169)	(121)			
Amortization of prior service cost	**10**	**1**	10	7	9	7	**11**	13	19
Recognized net actuarial loss (gain)	**64**	**17**	62	48	89	41	**(17)**	(20)	(16)
Net periodic benefit cost	**$ 284**	**103**	272	167	313	148	**52**	52	64

We recognized pension settlement losses of $18 million, $2 million and $11 million and special termination benefits of $2 million, $1 million and $1 million in 2008, 2007 and 2006, respectively. Curtailment losses of $1 million were recognized in 2007.

In determining net pension and other postretirement benefit costs, we amortize prior service costs on a straight-line basis over the average remaining service period of employees expected to receive benefits under the plan. For net gains and losses, we amortize 10 percent of the unamortized balance each year.

We have multiple nonpension postretirement benefit plans for health and life insurance. The health care plans are contributory and subject to various cost sharing features, with participant and company contributions adjusted annually; the life insurance plans are noncontributory. The measurement of the accumulated postretirement benefit obligation assumes a health care cost trend rate of 8.5 percent in 2009 that declines to 5.0 percent by 2023. A one-percentage-point change in the assumed health care cost trend rate would have the following effects on the 2008 amounts:

	Millions of Dollars	
	One-Percentage-Point	
	Increase	Decrease
Effect on total of service and interest cost components	$ 1	(1)
Effect on the postretirement benefit obligation	6	(5)

Plan Assets We follow a policy of broadly diversifying pension plan assets across asset classes, investment managers, and individual holdings. Asset classes that are considered appropriate include U.S. equities, non-U.S. equities, U.S. fixed income, non-U.S. fixed income, real estate, and private equity investments. Plan fiduciaries may consider and add other asset classes to the investment program from time to time. Our funding policy for U.S. plans is to contribute at least the minimum required by the Employee Retirement Income Security Act of 1974 and the Internal Revenue Code of 1986, as amended. Contributions to foreign plans are dependent upon local laws and tax regulations. In 2009, we expect to contribute approximately $930 million to our domestic qualified and nonqualified pension and postretirement benefit plans and $150 million to our international qualified and nonqualified pension and postretirement benefit plans.

125

A portion of U.S. pension plan assets is held as a participating interest in an insurance annuity contract. This participating interest is calculated as the market value of investments held under this contract, less the accumulated benefit obligation covered by the contract. At December 31, 2008, the participating interest in the annuity contract was valued at $138 million and consisted of $400 million in debt securities, less $262 million for the accumulated benefit obligation covered by the contract. At December 31, 2007, the participating interest in the annuity contract was valued at $159 million and consisted of $201 million in debt securities and $229 million in equity securities, less $271 million for the accumulated benefit obligation covered by the contract. The participating interest is not available for meeting general pension benefit obligations in the near term. No future company contributions are required and no new benefits are being accrued under this insurance annuity contract.

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

	Pension					
	U.S.			International		
	2008	2007	Target	**2008**	2007	Target
Asset Category						
Equity securities	**52%**	64	60	**39**	48	51
Debt securities	**48**	36	30	**56**	46	42
Real estate			5	**4**	5	6
Other			5	**1**	1	1
	100%	100	100	**100**	100	100

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

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

	Pension			
	U.S.		International	
	2008	2007	**2008**	2007
Asset Category				
Equity securities	**58%**	62	**39**	48
Debt securities	**36**	33	**56**	46
Participating interest in annuity contract	**6**	5		
Real estate			**4**	5
Other			**1**	1
	100%	100	**100**	100

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

	Millions of Dollars			
	Pension Benefits		Other Benefits	
	U.S.	Int l.	Gross	Subsidy Receipts
2009	$ 373	79	50	2
2010	380	83	53	
2011	469	86	56	
2012	442	91	58	
2013	470	97	60	
2014 2018	2,771	578	329	

Severance Accrual

As a result of the current business environment s impact on our operating and capital plans, a reduction in our overall employee work force is expected in 2009. Various business units and staff groups recorded accruals in the fourth quarter of 2008 for severance and related employee benefits totaling $162 million, all of which is classified as short-term.

Defined Contribution Plans

Most U.S. employees (excluding retail service station employees) are eligible to participate in either the ConocoPhillips Savings Plan (CPSP) or the Burlington Resources Savings Plan (BR Savings Plan). Employees can deposit up to 30 percent of their eligible pay up to the statutory limit ($15,500 in 2008) in the thrift feature of the CPSP to a choice of approximately 43 investment funds. ConocoPhillips matches contribution deposits, up to 1.25 percent of eligible pay. Company contributions charged to expense for the CPSP and predecessor plans, excluding the stock savings feature (discussed below), were $22 million in 2008, $21 million in 2007, and $19 million in 2006. For the BR Savings Plan, ConocoPhillips matches deposits, up to 6 percent or 8 percent of the employee s eligible pay based upon years of service. During 2008, ConocoPhillips contributed $5 million to the BR Savings Plan, to match eligible contributions by employees.

Assets of the BR Savings Plan were merged into the CPSP effective at close of business on December 31, 2008, and the BR Savings Plan participants became participants in CPSP.

The stock savings feature of the CPSP is a leveraged employee stock ownership plan. Employees may elect to participate in the stock savings feature by contributing 1 percent of eligible pay and receiving an allocation of shares of common stock proportionate to the amount of contribution.

In 1990, the Long-Term Stock Savings Plan of Phillips Petroleum Company (now the stock savings feature of the CPSP) borrowed funds that were used to purchase previously unissued shares of company common stock. Since the company guarantees the CPSP s borrowings, the unpaid balance is reported as a liability of the company and unearned compensation is shown as a reduction of common stockholders equity. Dividends on all shares are charged against retained earnings. The debt is serviced by the CPSP from company contributions and dividends received on certain shares of common stock held by the plan, including all unallocated shares. The shares held by the stock savings feature of the CPSP are released for allocation to participant accounts based on debt service payments on CPSP borrowings. In addition, during the period from 2009 through 2012, when no debt principal payments are scheduled to occur, we have committed to make direct contributions of stock to the stock savings feature of the CPSP, or make prepayments on CPSP borrowings, to ensure a certain minimum level of stock allocation to participant accounts.

Table of Contents

We recognize interest expense as incurred and compensation expense based on the fair market value of the stock contributed or on the cost of the unallocated shares released, using the shares-allocated method. We recognized total CPSP expense related to the stock savings feature of $111 million, $148 million and $126 million in 2008, 2007 and 2006, respectively, all of which was compensation expense. In 2008, 2007 and 2006, we contributed 1,668,456 shares, 1,856,224 shares and 1,921,688 shares, respectively, of company common stock from the Compensation and Benefits Trust. The shares had a fair market value of $120 million, $155 million and $132 million, respectively. Dividends used to service debt were $41 million, $39 million and $37 million in 2008, 2007 and 2006, respectively. These dividends reduced the amount of compensation expense recognized each period. Interest incurred on the CPSP debt in 2008, 2007 and 2006 was $6 million, $11 million and $12 million, respectively.

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

	2008	2007
Unallocated shares	**7,208,150**	9,040,949
Allocated shares	**18,000,395**	17,648,368
Total shares	**25,208,545**	26,689,317

The fair value of unallocated shares at December 31, 2008 and 2007, was $373 million and $798 million, respectively.

We have several defined contribution plans for our international employees, each with its own terms and eligibility depending on location. Total compensation expense recognized for these international plans was approximately $53 million in 2008, $44 million in 2007 and $39 million in 2006.

Share-Based Compensation Plans

The 2004 Omnibus Stock and Performance Incentive Plan (the Plan) was approved by shareholders in May 2004. Over its 10-year life, the Plan allows the issuance of up to 70 million shares of our common stock for compensation to our employees, directors and consultants. After approval of the Plan, the heritage plans were no longer used for further awards. Of the 70 million shares available for issuance under the Plan, 40 million shares of common stock are available for incentive stock options, and no more than 40 million shares may be used for awards in stock.

Our share-based compensation programs generally provide accelerated vesting (i.e., a waiver of the remaining period of service required to earn an award) for awards held by employees at the time of their retirement. For share-based awards granted prior to our adoption of SFAS No. 123(R), we recognize expense over the period of time during which the employee earns the award, accelerating the recognition of expense only when an employee actually retires. For share-based awards granted after our adoption of SFAS No. 123(R) on January 1, 2006, we recognize share-based compensation expense over the shorter of: 1) the service period (i.e., the stated period of time required to earn the award); or 2) the period beginning at the start of the service period and ending when an employee first becomes eligible for retirement, but not less than six months, as this is the minimum period of time required for an award to not be subject to forfeiture.

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

Table of Contents

Total share-based compensation expense recognized in income and the associated tax benefit for the three years ended December 31, 2008, was as follows:

	Millions of Dollars		
	2008	2007	2006
Compensation cost	**$ 193**	242	140
Tax benefit	**67**	85	54

Stock Options Stock options granted under the provisions of the Plan and earlier plans permit purchase of our common stock at exercise prices equivalent to the average market price of the stock on the date the options were granted. The options have terms of 10 years and generally vest ratably, with one-third of the options awarded vesting and becoming exercisable on each anniversary date following the date of grant. Options awarded to employees already eligible for retirement vest within six months of the grant date, but those options do not become exercisable until the end of the normal vesting period.

The following summarizes our stock option activity for the three years ended December 31, 2008:

	Options	Weighted-Average Exercise Price	Weighted-Average Grant-Date Fair Value	Millions of Dollars Aggregate Intrinsic Value
Outstanding at December 31, 2005	57,396,746	$ 27.31		
Burlington Resources acquisition at March 31, 2006	4,927,116	33.95		
Granted	1,809,281	59.33	$ 16.16	
Exercised	(9,737,765)	24.32		$ 416
Forfeited	(341,759)	60.58		
Expired	(4,840)	50.16		
Outstanding at December 31, 2006	54,048,779	$ 29.31		
Granted	2,530,648	66.37	$ 17.86	
Exercised	(12,176,988)	26.29		$ 926
Forfeited	(268,177)	65.02		
Expired or cancelled	(29,407)	17.00		
Outstanding at December 31, 2007	44,104,855	$ 32.06		
Granted	**2,211,202**	**79.35**	**$ 18.66**	
Exercised	**(9,493,818)**	**28.39**		**$ 535**
Forfeited	**(184,148)**	**73.91**		
Expired or cancelled	**(22,338)**	**42.65**		
Outstanding at December 31, 2008	**36,615,753**	**$ 35.65**		
Vested at December 31, 2008	**34,062,503**	**$ 32.94**		**$ 693**
Exercisable at December 31, 2008	**32,607,060**	**$ 31.16**		**$ 693**

The weighted-average remaining contractual term of vested options and exercisable options at December 31, 2008, was 3.98 years and 3.77 years, respectively.

Table of Contents

During 2008, we received $260 million in cash and realized a tax benefit of $161 million from the exercise of options. At December 31, 2008, the remaining unrecognized compensation expense from unvested options was $18 million, which will be recognized over a weighted-average period of 11 months, the longest period being 25 months.

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

	2008	2007	2006
Assumptions used			
Risk-free interest rate	**3.21%**	4.77	4.63
Dividend yield	**2.50%**	2.50	2.50
Volatility factor	**27.78%**	26.10	26.10
Expected life (years)	**5.82**	6.70	7.18

The ranges in the assumptions used were as follows:

	2008		2007		2006	
	High	**Low**	High	Low	High	Low
Ranges used						
Risk-free interest rate	**3.45%**	**2.27**	4.90	4.77	5.15	4.54
Dividend yield	**2.50**	**2.50**	2.50	2.50	2.50	2.50
Volatility factor	**32.10**	**26.70**	26.10	26.10	26.50	25.90

We calculate volatility using all of the ConocoPhillips end-of-week closing stock prices available since the merger of Conoco and Phillips Petroleum on August 31, 2002, and will continue to do so until the span of data used equals the expected life of the options granted. We periodically calculate the average period of time lapsed between grant dates and exercise dates of past grants to estimate the expected life of new option grants.

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

Table of Contents

The following summarizes our stock unit activity for the three years ended December 31, 2008:

	Stock Units	Weighted-Average Grant-Date Fair Value		Millions of Dollars Total Fair Value	
Outstanding at December 31, 2005	3,892,404	$	38.34		
Granted	1,480,294		57.77		
Forfeited	(118,461)		45.92		
Issued	(167,099)			$	11
Outstanding at December 31, 2006	5,087,138	$	43.75		
Granted	1,721,521		65.33		
Forfeited	(162,992)		52.57		
Issued	(975,756)			$	36
Outstanding at December 31, 2007	5,669,911	$	51.30		
Granted	**1,797,803**		**77.42**		
Forfeited	**(128,888)**		**62.82**		
Issued	**(1,411,128)**			**$**	**59**
Outstanding at December 31, 2008	**5,927,698**	**$**	**61.16**		
Not Vested at December 31, 2008	**5,285,087**	**$**	**60.50**		

At December 31, 2008, the remaining unrecognized compensation cost from the unvested units was $161 million, which will be recognized over a weighted-average period of 25 months, the longest period being 49 months.

Performance Share Program Under the Plan, we also annually grant to senior management restricted stock units that do not vest until either (i) with respect to awards for periods beginning before 2009, the employee becomes eligible for retirement by reaching age 55 with five years of service or (ii) with respect to awards for periods beginning in 2009, five years after the grant date of the award (although recipients can elect to defer the lapsing of restrictions until retirement after reaching age 55 with five years of service), so we recognize compensation expense for these awards beginning on the date of grant and ending on the date the units are scheduled to vest. Since these awards are authorized three years prior to the grant date, for employees eligible for such retirement by or shortly after the grant date, we recognize compensation expense over the period beginning on the date of authorization and ending on the date of grant. These units are settled by issuing one share of ConocoPhillips common stock per unit, generally when the employee retires from ConocoPhillips. Until issued as stock, recipients of the units receive a quarterly cash payment of a dividend equivalent that is charged to expense. In its current form, the first grant of units under this program was in 2006.

Table of Contents

The following summarizes our Performance Share Program activity for the three years ended December 31, 2008:

	Performance Share Stock Units	Weighted-Average Grant-Date Fair Value	Millions of Dollars Total Fair Value
Outstanding at December 31, 2005		$	
Granted	1,641,216	59.08	
Issued	(184,975)		$ 12
Outstanding at December 31, 2006	1,456,241	$ 59.08	
Granted	1,349,475	66.37	
Forfeited	(22,062)	62.45	
Issued	(178,357)		$ 12
Outstanding at December 31, 2007	2,605,297	$ 62.49	
Granted	**1,291,453**	**79.38**	
Forfeited	**(30,862)**	**69.24**	
Issued	**(689,710)**		**$ 58**
Outstanding at December 31, 2008	**3,176,178**	**$ 68.13**	
Not Vested at December 31, 2008	**1,319,719**	**$ 43.41**	

At December 31, 2008, the remaining unrecognized compensation cost from unvested Performance Share awards was $57 million, which will be recognized over a weighted-average period of 47 months, the longest period being 12 years.

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

The following summarizes the aggregate activity of these restricted shares and units for the three years ended December 31, 2008:

	Stock Units	Weighted-Average Grant-Date Fair Value	Millions of Dollars Total Fair Value
Outstanding at December 31, 2005	3,344,941	$ 29.16	
Granted	248,421	64.48	
Burlington Resources acquisition	523,769	64.95	
Issued	(239,257)		$ 16
Cancelled	(275,499)	47.56	
Outstanding at December 31, 2006	3,602,375	$ 33.68	
Granted	293,024	67.30	
Issued	(227,766)		$ 17

Cancelled	(180,489)		50.39			
Outstanding at December 31, 2007	3,487,144	$	34.41			
Granted	**237,642**		**78.59**			
Issued	**(128,803)**			**$**	**9**	
Cancelled	**(231,963)**		**40.08**			
Outstanding at December 31, 2008	**3,364,020**	**$**	**36.75**			
Not Vested at December 31, 2008	**313,974**	**$**	**72.95**			

Table of Contents

At December 31, 2008, the remaining unrecognized compensation cost from the unvested units was $12 million, which will be recognized over a weighted-average period of 18 months, the longest period being 25 months.

Compensation and Benefits Trust

The Compensation and Benefits Trust (CBT) is an irrevocable grantor trust, administered by an independent trustee and designed to acquire, hold and distribute shares of our common stock to fund certain future compensation and benefit obligations of the company. The CBT does not increase or alter the amount of benefits or compensation that will be paid under existing plans, but offers us enhanced financial flexibility in providing the funding requirements of those plans. We also have flexibility in determining the timing of distributions of shares from the CBT to fund compensation and benefits, subject to a minimum distribution schedule. The trustee votes shares held by the CBT in accordance with voting directions from eligible employees, as specified in a trust agreement with the trustee.

We sold 58.4 million shares of previously unissued company common stock to the CBT in 1995 for $37 million of cash, previously contributed to the CBT by us, and a promissory note from the CBT to us of $952 million. The CBT is consolidated by ConocoPhillips; therefore, the cash contribution and promissory note are eliminated in consolidation. Shares held by the CBT are valued at cost and do not affect earnings per share or total common stockholders equity until after they are transferred out of the CBT. In 2008 and 2007, shares transferred out of the CBT were 1,668,456 and 1,856,224, respectively. At December 31, 2008, the CBT had 40.5 million shares remaining. All shares are required to be transferred out of the CBT by January 1, 2021. The CBT, together with two smaller grantor trusts, comprise the Grantor trusts line in the equity section of the consolidated balance sheet.

Note 21 Income Taxes

Income taxes charged to income (loss) were:

	Millions of Dollars		
	2008	2007	2006
Income Taxes			
Federal			
Current	**$ 3,245**	3,944	4,313
Deferred	**(227)**	312	(77)
Foreign			
Current	**10,268**	7,035	7,581
Deferred	**(312)**	(474)	392
State and local			
Current	**543**	602	622
Deferred	**(112)**	(38)	(48)
	$ 13,405	11,381	12,783

Table of Contents

Deferred income taxes reflect the net tax effect of temporary differences between the carrying amounts of assets and liabilities for financial reporting purposes and the amounts used for tax purposes. Major components of deferred tax liabilities and assets at December 31 were:

	Millions of Dollars	
	2008	2007
Deferred Tax Liabilities		
Properties, plants and equipment, and intangibles	**$ 20,563**	23,344
Investment in joint ventures	**1,778**	1,300
Inventory	**283**	197
Partnership income deferral	**1,172**	1,501
Other	**564**	725
Total deferred tax liabilities	**24,360**	27,067
Deferred Tax Assets		
Benefit plan accruals	**1,819**	1,603
Asset retirement obligations and accrued environmental costs	**3,232**	3,135
Deferred state income tax	**289**	390
Other financial accruals and deferrals	**712**	539
Loss and credit carryforwards	**1,657**	1,716
Other	**338**	251
Total deferred tax assets	**8,047**	7,634
Less valuation allowance	**(1,340)**	(1,269)
Net deferred tax assets	**6,707**	6,365
Net deferred tax liabilities	**$ 17,653**	20,702

Current assets, long-term assets, current liabilities and long-term liabilities included deferred taxes of $457 million, $58 million, $1 million and $18,167 million, respectively, at December 31, 2008, and $329 million, $26 million, $39 million and $21,018 million, respectively, at December 31, 2007.

We have loss and credit carryovers in multiple taxing jurisdictions. These attributes generally expire between 2009 and 2028 with some carryovers having indefinite carryforward periods.

Valuation allowances have been established for certain loss and credit carryforwards that reduce deferred tax assets to an amount that will, more likely than not, be realized. During 2008, valuation allowances increased a total of $71 million. This reflects increases of $303 million primarily related to U.S. foreign tax credit and foreign and state tax loss carryforwards, partially offset by decreases of $232 million related to utilization of credits and loss carryforwards, currency effects and asset relinquishment. Based on our historical taxable income, expectations for the future, and available tax-planning strategies, management expects remaining net deferred tax assets will be realized as offsets to reversing deferred tax liabilities and as offsets to the tax consequences of future taxable income. None of the future tax benefit for recognition of deferred tax assets that have valuation allowances, if any, will be allocated to goodwill due to the effect of SFAS No. 141 (Revised), Business Combinations (SFAS No. 141(R)). For additional information on SFAS No. 141(R), see Note 27 New Accounting Standards.

At December 31, 2008 and 2007, income considered to be permanently reinvested in certain foreign subsidiaries and foreign corporate joint ventures totaled approximately $3,319 million and $6,606 million, respectively. The change from 2007 relates primarily to the impairment of our LUKOIL investment in 2008. Deferred income taxes have not been provided on this income, as we do not plan to initiate any action that would require the payment of income taxes.

It is not practicable to estimate the amount of additional tax that might be payable on this foreign income if distributed.

Table of Contents

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 requires recognition of a tax benefit if it is more likely than not it will be sustained upon examination. We adopted FIN 48 effective January 1, 2007. The adoption did not have a material impact on our consolidated financial statements.

The following table shows a reconciliation of the beginning and ending unrecognized tax benefits for 2007 and 2008.

	Millions of Dollars	
	2008	2007
Balance at January 1	**$ 1,143**	912
Additions based on tax positions related to the current year	**7**	273
Additions for tax positions of prior years	**186**	145
Reductions for tax positions of prior years	**(249)**	(168)
Settlements	**(16)**	(15)
Lapse of statute	**(3)**	(4)
Balance at December 31	**$ 1,068**	1,143

Included in the balance of unrecognized tax benefits for 2008 and 2007 were $862 million and $698 million, respectively, which, if recognized, would affect our effective tax rate. The increase from 2007 was primarily due to the effect of SFAS No. 141(R).

At December 31, 2008 and 2007, accrued liabilities for interest and penalties totaled $147 million and $137 million, respectively, net of accrued income taxes. Interest and penalties affecting earnings in 2008 and 2007 were $28 million and $46 million, respectively.

We and our subsidiaries file tax returns in the U.S. federal jurisdiction and in many foreign and state jurisdictions. Audits in major jurisdictions are generally complete as follows: United Kingdom (2001), Canada (2003), United States (2004) and Norway (2007). Issues in dispute for audited years and audits for subsequent years are ongoing and in various stages of completion in the many jurisdictions in which we operate around the world. As a consequence, the balance in unrecognized tax benefits can be expected to fluctuate from period to period. It is reasonably possible such changes could be significant when compared with our total unrecognized tax benefits, but the amount of change is not estimable.

Table of Contents

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

	Millions of Dollars			Percent of Pretax Income		
	2008	2007	2006	**2008**	2007	2006
Income (loss) before income taxes						
United States	**$ 10,050**	13,939	13,376	**(279.7)%**	59.9	47.2
Foreign	**11,800**	9,333	14,957	**(328.4)**	40.1	52.8
Goodwill impairment	**(25,443)**			**708.1**		
	$ (3,593)	23,272	28,333	**100.0%**	100.0	100.0
Federal statutory income tax	**$ (1,257)**	8,145	9,917	**35.0%**	35.0	35.0
Goodwill impairment	**8,905**			**(247.8)**		
Foreign taxes in excess of federal statutory rate	**5,694**	3,254	2,697	**(158.5)**	14.0	9.5
Federal manufacturing deduction	**(182)**	(250)	(119)	**5.1**	(1.1)	(0.4)
State income tax	**280**	367	373	**(7.8)**	1.6	1.3
Other	**(35)**	(135)	(85)	**0.9**	(0.6)	(0.3)
	$ 13,405	11,381	12,783	**(373.1)%**	48.9	45.1

Our effective tax rate in 2008 was a negative 373 percent, compared with a positive 49 percent in 2007. The change in the effective tax rate for 2008 was primarily due to the impact of impairments relating to goodwill and to our LUKOIL investment taken in the fourth quarter of 2008. For additional information on the impairments, see Note 9 Goodwill and Intangibles and Note 7 Investments, Loans and Long-Term Receivables.

Tax rate changes in 2008 did not have a significant impact on our 2008 income tax expense. Our 2007 tax expense was decreased $204 million and $141 million, respectively, due to remeasurement of deferred tax liabilities resulting from tax rate reductions in Canada and Germany. Our 2006 tax expense was increased $470 million due to remeasurement of deferred tax liabilities and the current year impact of increases in the U.K. tax rate. This was mostly offset by a 2006 reduction in tax expense of $435 million due to the remeasurement of deferred tax liabilities from the 2006 Canadian graduated tax rate reduction and an Alberta provincial tax rate change.

Table of Contents

Note 22 Other Comprehensive Income (Loss)
The components and allocated tax effects of other comprehensive income (loss) follow:

	Millions of Dollars		
	Before-Tax	Tax Expense (Benefit)	After-Tax
2008			
Defined benefit pension plans:			
Prior service cost arising during the year	**$ 30**	**22**	**8**
Reclassification adjustment for amortization of prior service cost included in net loss	**22**	**8**	**14**
Net prior service cost	**52**	**30**	**22**
Net loss arising during the year	**(1,523)**	**(535)**	**(988)**
Reclassification adjustment for amortization of prior net losses included in net loss	**64**	**26**	**38**
Net loss	**(1,459)**	**(509)**	**(950)**
Nonsponsored plans*	**(41)**		**(41)**
Foreign currency translation adjustments	**(5,552)**	**(88)**	**(5,464)**
Hedging activities	**(4)**	**(2)**	**(2)**
Other comprehensive loss	**$ (7,004)**	**(569)**	**(6,435)**
2007			
Defined benefit pension plans:			
Prior service cost arising during the year	$ 65	20	45
Reclassification adjustment for amortization of prior service cost included in net income	30	12	18
Net prior service cost	95	32	63
Net gain arising during the year	222	67	155
Reclassification adjustment for amortization of prior net losses included in net income	90	32	58
Net gain	312	99	213
Nonsponsored plans*	(2)		(2)
Foreign currency translation adjustments	3,214	139	3,075
Hedging activities	(3)	1	(4)
Other comprehensive income	$ 3,616	271	3,345
2006			

Minimum pension liability adjustment	$	53	20	33
Foreign currency translation adjustments		913	(100)	1,013
Hedging activities		4		4
Other comprehensive income	$	970	(80)	1,050

* *Plans for which ConocoPhillips is not the primary obligor primarily those administered by equity affiliates.*

Deferred taxes have not been provided on temporary differences related to foreign currency translation adjustments for investments in certain foreign subsidiaries and foreign corporate joint ventures that are considered permanent in duration.

Table of Contents

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

	Millions of Dollars	
	2008	2007
Defined benefit pension liability adjustments	**$ (1,434)**	(465)
Foreign currency translation adjustments	**(431)**	5,033
Deferred net hedging loss	**(10)**	(8)
Accumulated other comprehensive income (loss)	**$ (1,875)**	4,560

Note 23 Cash Flow Information

	Millions of Dollars		
	2008	2007	2006
Noncash Investing and Financing Activities			
Issuance of stock and options for the acquisition of Burlington Resources	**$**		16,343
Investment in an upstream business venture through issuance of an acquisition obligation		7,313	
Investment in a downstream business venture through contribution of noncash assets and liabilities		2,428	
Increase in PP&E related to an increase in asset retirement obligations	**1,117**	919	464
Cash Payments			
Interest	**$ 858**	1,040	958
Income taxes	**13,122**	11,330	13,050

138

Table of Contents

Note 24 Other Financial Information

		Millions of Dollars Except Per Share Amounts		
		2008	2007	2006
Interest and Debt Expense				
Incurred				
Debt	$	**1,189**	1,369	1,409
Other		**314**	449	136
		1,503	1,818	1,545
Capitalized		**(568)**	(565)	(458)
Expensed	$	**935**	1,253	1,087
Other Income				
Interest income	$	**245**	342	165
Gain on asset dispositions		**891**	1,348	116
Business interruption insurance recoveries*		**2**	52	239
Other, net		**(48)**	229	165
	$	**1,090**	1,971	685

* *Primarily related to 2005 hurricanes in the Gulf of Mexico and southern United States.*

Research and Development Expenditures expensed	$	**209**	160	117
Advertising Expenses	$	**96**	84	87
Shipping and Handling Costs*	$	**1,443**	1,493	1,415

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

Cash Dividends paid per common share	$	**1.88**	1.64	1.44

Foreign Currency Transaction Gains (Losses) after-tax			
E&P	**$ 216**	216	(44)
Midstream	**1**	(2)	
R&M	**(173)**	(13)	60
LUKOIL Investment	**(27)**	5	
Chemicals			
Emerging Businesses	**(7)**	1	1
Corporate and Other	**(72)**	(120)	65
	$ (62)	87	82

Note 25 Related Party Transactions

Significant transactions with related parties were:

		Millions of Dollars	
	2008	2007	2006*
Operating revenues (a)	$ **13,097**	10,949	8,808
Purchases (b)**	**19,409**	15,722	7,072
Operating expenses and selling, general and administrative expenses (c)	**515**	416	386
Net interest expense (d)	**66**	99	(13)

* *Restated to include additional related party transactions.*

** *The increase in 2007 is primarily due to purchases from the WRB business venture.*

(a) We sold natural gas to DCP Midstream and crude oil to the Malaysian Refining Company Sdn. Bhd. (MRC), among others, for processing and marketing. Natural gas liquids, solvents and petrochemical feedstocks were sold to Chevron Phillips Chemical Company LLC (CPChem), gas oil and hydrogen feedstocks were sold to Excel Paralubes and refined products were sold primarily to CFJ Properties and LUKOIL. Natural gas, crude oil, blendstock and other intermediate products were sold to WRB Refining LLC. In addition, we charged several of our affiliates, including CPChem, Merey Sweeny L.P. (MSLP) and Hamaca Holding LLC (until expropriation on June 26, 2007), for the use of common facilities, such as steam generators, waste and water treaters, and warehouse facilities.

(b) We purchased refined products from WRB. We purchased natural gas and natural gas liquids from DCP Midstream and CPChem for use in our refinery processes and other feedstocks from various affiliates. We purchased crude oil from LUKOIL, upgraded crude oil from Petrozuata C.A. (until expropriation on June 26, 2007) and refined products from MRC. We also paid fees to various pipeline equity companies for transporting finished refined products, as well as a price upgrade to MSLP for heavy crude processing. We purchased base oils and fuel products from Excel Paralubes for use in our refinery and specialty businesses.

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

(d) We paid and/or received interest to/from various affiliates, including FCCL Oil Sands Partnership. See Note 7 Investments, Loans and Long-Term Receivables, for additional information on loans to affiliated companies.

Note 26 Segment Disclosures and Related Information

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

1) E&P This segment primarily explores for, produces, transports and markets crude oil, natural gas and natural gas liquids on a worldwide basis. At December 31, 2008, our E&P operations were producing in the United States, Norway, the United Kingdom, Canada, Ecuador, Australia, offshore Timor-Leste in the Timor Sea, Indonesia, China, Vietnam, Libya, Nigeria, Algeria and Russia. The E&P segment s U.S. and international operations are disclosed separately for reporting purposes.
2) Midstream This segment gathers, processes and markets natural gas produced by ConocoPhillips and others, and fractionates and markets natural gas liquids, predominantly in the United States and Trinidad. The Midstream segment primarily consists of our 50 percent equity investment in DCP Midstream, LLC.
3) R&M This segment purchases, refines, markets and transports crude oil and petroleum products, mainly in the United States, Europe and Asia. At December 31, 2008, we owned or had an interest in 12 refineries in the United States, one in the United Kingdom, one in Ireland, two in Germany, and one in Malaysia. The R&M segment s U.S. and international operations are disclosed separately for reporting purposes.
4) LUKOIL Investment This segment represents our investment in the ordinary shares of OAO LUKOIL, an international, integrated oil and gas company headquartered in Russia. At December 31, 2008, our ownership interest was 20 percent based on issued shares and 20.06 percent based on estimated shares outstanding. See Note 7 Investments, Loans and Long-Term Receivables, for additional information.
5) Chemicals This segment manufactures and markets petrochemicals and plastics on a worldwide basis. The Chemicals segment consists of our 50 percent equity investment in Chevron Phillips Chemical Company LLC.
6) Emerging Businesses This 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 and innovation of new technologies, such as those related to conventional and nonconventional hydrocarbon recovery (including heavy oil), refining, alternative energy, biofuels and the environment.

Corporate and Other includes general corporate overhead, most interest expense, discontinued operations, restructuring charges, and various other corporate activities. Corporate assets include all cash and cash equivalents.

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

Table of Contents

Analysis of Results by Operating Segment

	Millions of Dollars		
	2008	2007	2006
Sales and Other Operating Revenues			
E&P			
United States	$ **51,378**	36,974	35,335
International	**36,972**	24,617	28,111
Intersegment eliminations U.S.	**(8,034)**	(6,096)	(5,438)
Intersegment eliminations international	**(10,498)**	(7,341)	(7,842)
E&P	**69,818**	48,154	50,166
Midstream			
Total sales	**6,791**	5,106	4,461
Intersegment eliminations	**(227)**	(245)	(1,037)
Midstream	**6,564**	4,861	3,424
R&M			
United States	**117,727**	96,154	95,314
International	**47,520**	38,598	35,439
Intersegment eliminations U.S.	**(965)**	(540)	(855)
Intersegment eliminations international	**(52)**	(11)	(21)
R&M	**164,230**	134,201	129,877
LUKOIL Investment			
Chemicals	**11**	10	13
Emerging Businesses			
Total sales	**1,060**	656	675
Intersegment eliminations	**(861)**	(458)	(515)
Emerging Businesses	**199**	198	160
Corporate and Other	**20**	13	10
Consolidated sales and other operating revenues	$ **240,842**	187,437	183,650
Depreciation, Depletion, Amortization and Impairments			
E&P			
United States	$ **3,725**	3,328	2,901
International	**5,096**	9,121	3,445
Goodwill impairment	**25,443**		
Total E&P	**34,264**	12,449	6,346

Midstream	**6**	14	29
R&M			
United States	**1,129**	609	1,014
International	**425**	139	458
Total R&M	**1,554**	748	1,472
LUKOIL Investment	**7,410**		
Chemicals			
Emerging Businesses	**193**	39	58
Corporate and Other	**124**	78	62
Consolidated depreciation, depletion, amortization and impairments	**$ 43,551**	13,328	7,967

Table of Contents

	Millions of Dollars		
	2008	2007	2006
Equity in Earnings of Affiliates			
E&P			
United States	$ **57**	11	20
International	**235**	302	782
Total E&P	**292**	313	802
Midstream	**810**	599	618
R&M			
United States	**836**	1,710	466
International	**178**	240	151
Total R&M	**1,014**	1,950	617
LUKOIL Investment	**2,011***	1,875	1,481
Chemicals	**128**	350	665
Emerging Businesses	**(5)**		5
Corporate and Other			
Consolidated equity in earnings of affiliates	$ **4,250**	5,087	4,188

** Does not include a $7,410 million impairment of our LUKOIL investment presented as a separate line item in the consolidated statement of operations.*

	2008	2007	2006
Income Taxes			
E&P			
United States	$ **2,617**	2,231	2,545
International	**9,621**	6,372	7,584
Total E&P	**12,238**	8,603	10,129
Midstream	**261**	237	248
R&M			
United States	**934**	2,571	2,334
International	**214**	113	218
Total R&M	**1,148**	2,684	2,552
LUKOIL Investment	**49**	45	37
Chemicals	**15**	(13)	171
Emerging Businesses	**(6)**	(33)	(2)
Corporate and Other	**(300)**	(142)	(352)

Consolidated income taxes	**$ 13,405**	11,381	12,783
Net Income (Loss)			
E&P			
United States	**$ 4,988**	4,248	4,348
International	**6,976**	367	5,500
Goodwill impairment	**(25,443)**		
Total E&P	**(13,479)**	4,615	9,848
Midstream	**541**	453	476
R&M			
United States	**1,540**	4,615	3,915
International	**782**	1,308	566
Total R&M	**2,322**	5,923	4,481
LUKOIL Investment	**(5,488)**	1,818	1,425
Chemicals	**110**	359	492
Emerging Businesses	**30**	(8)	15
Corporate and Other	**(1,034)**	(1,269)	(1,187)
Consolidated net income (loss)	**$ (16,998)**	11,891	15,550

Table of Contents

		Millions of Dollars	
	2008	2007	2006
Investments In and Advances To Affiliates			
E&P			
United States	$ **1,368**	1,059	690
International	**16,772**	12,055	4,346
Total E&P	**18,140**	13,114	5,036
Midstream	**1,033**	1,178	1,319
R&M			
United States	**3,677**	3,500	698
International	**1,326**	1,091	948
Total R&M	**5,003**	4,591	1,646
LUKOIL Investment	**5,452**	11,162	9,564
Chemicals	**2,186**	2,203	2,255
Emerging Businesses	**75**	79	
Corporate and Other			
Consolidated investments in and advances to affiliates*	$ **31,889**	32,327	19,820
* *Includes amounts classified as held for sale:*	*$ 2*	*48*	*158*
Total Assets			
E&P			
United States	$ **36,962**	35,160	35,523
International	**58,912**	59,412	48,143
Goodwill		25,569	27,712
Total E&P	**95,874**	120,141	111,378
Midstream	**1,455**	2,016	2,045
R&M			
United States	**22,554**	24,336	22,936
International	**7,942**	9,766	9,135
Goodwill	**3,778**	3,767	3,776
Total R&M	**34,274**	37,869	35,847
LUKOIL Investment	**5,455**	11,164	9,564
Chemicals	**2,217**	2,225	2,379
Emerging Businesses	**924**	1,230	977
Corporate and Other	**2,666**	3,112	2,591

Consolidated total assets	$ **142,865**	177,757	164,781
Capital Expenditures and Investments*			
E&P			
United States	$ **5,250**	3,788	2,828
International	**11,206**	6,147	6,685
Total E&P	**16,456**	9,935	9,513
Midstream	**4**	5	4
R&M			
United States	**1,643**	1,146	1,597
International	**626**	240	1,419
Total R&M	**2,269**	1,386	3,016
LUKOIL Investment			2,715
Chemicals			
Emerging Businesses	**156**	257	83
Corporate and Other	**214**	208	265
Consolidated capital expenditures and investments	$ **19,099**	11,791	15,596

* *Net of cash acquired.*

Table of Contents

	Millions of Dollars		
	2008	2007	2006
Interest Income and Expense			
Interest income			
Corporate	$ **128**	246	106
E&P	**115**	96	57
R&M	**2**		
Interest and debt expense			
Corporate	**762**	1,066	1,087
E&P	**173**	187	

Geographic Information

	Millions of Dollars					
	Sales and Other Operating Revenues*			Long-Lived Assets**		
	2008	2007	2006	**2008**	2007	2006
United States	**$ 166,496**	131,433	127,869	**52,972**	50,714	48,418
Australia***	**2,735**	1,633	1,836	**8,656**	3,420	3,542
Canada	**5,226**	4,727	5,554	**20,429**	24,758	14,831
Norway	**3,036**	2,479	2,480	**5,002**	6,180	4,982
Russia				**7,604**	13,359	10,886
United Kingdom	**29,699**	20,680	19,510	**5,844**	7,995	7,755
Other foreign countries	**33,650**	26,485	26,401	**15,919**	14,904	15,607
Worldwide consolidated	**$ 240,842**	187,437	183,650	**116,426**	121,330	106,021

* *Sales and other operating revenues are attributable to countries based on the location of the operations generating the revenues.*

** *Defined as net properties, plants and equipment plus investments in and advances to affiliated companies. Includes* *amounts classified as held for sale.*

*** *Includes amounts related to the joint petroleum development area with shared ownership held by Australia and Timor-Leste.*

Note 27 New Accounting Standards

In December 2007, the FASB issued SFAS No. 141 (Revised), Business Combinations (SFAS No. 141(R)). This Statement will apply to all transactions in which an entity obtains control of one or more other businesses. In general, SFAS No. 141(R) requires the acquiring entity in a business combination to recognize the fair value of all the assets acquired and liabilities assumed in the transaction; establishes the acquisition date as the fair value measurement point; and modifies the disclosure requirements. Additionally, it changes the accounting treatment for transaction costs, acquired contingent arrangements, in-process research and development, restructuring costs, changes in deferred tax asset valuation allowances as a result of business combination, and changes in income tax uncertainties after the acquisition date. This Statement applies prospectively to business combinations for which the acquisition date is on or after January 1, 2009. However, starting January 1, 2009, accounting for changes in valuation allowances for acquired deferred tax assets and the resolution of uncertain tax positions for prior business combinations will impact tax expense instead of impacting goodwill.

Also in December 2007, the FASB issued SFAS No. 160, Noncontrolling Interests in Consolidated Financial Statements an amendment of ARB No. 51, which requires noncontrolling interests, also called minority interests, to be presented as a separate item in the equity section of the consolidated balance sheet. It also requires the amount of consolidated net income attributable to the noncontrolling interest to be clearly presented on the face of the consolidated income statement. Additionally, this Statement clarifies that changes in a parent s ownership interest in a subsidiary that do not result in deconsolidation are equity transactions, and when a subsidiary is deconsolidated, it requires gain or loss recognition in net income based on the fair value on the deconsolidation date. This Statement is effective January 1, 2009, and will be applied prospectively with the exception of the presentation and disclosure requirements, which must be applied retrospectively for all periods presented.

In March 2008, the FASB issued SFAS No. 161, Disclosures about Derivative Instruments and Hedging Activities an amendment of FASB No. 133. This Statement expands disclosure requirements of SFAS No. 133, Accounting for Derivative Instruments and Hedging Activities, for derivative instruments within the scope of that Statement to provide greater transparency. This includes the disclosure of the additional information regarding how and why derivative instruments are used, how derivatives are accounted for, and how they affect an entity s financial performance. This Statement is effective for interim and annual financial statements beginning with the first quarter of 2009, but it will not have any impact on our consolidated financial statements, other than the additional disclosures.

In November 2008, the FASB reached a consensus on EITF Issue No. 08-6, Equity Method Investment Accounting Considerations (EITF 08-6), which was issued to clarify how the application of equity method accounting will be affected by SFAS No. 141(R) and SFAS No. 160. EITF 08-6 clarifies that an entity shall continue to use the cost accumulation model for its equity method investments. It also confirms past accounting practices related to the treatment of contingent consideration and the use of the impairment model under APB Opinion No. 18, The Equity Method of Accounting for Investments in Common Stock. Additionally, it requires an equity method investor to account for a share issuance by an investee as if the investor had sold a proportionate share of the investment. This Issue is effective January 1, 2009, and will be applied prospectively.

In December 2008, the FASB issued FASB Staff Position (FSP) No. 132(R)-1, Employers Disclosures about Postretirement Benefit Plan Assets, to improve the transparency associated with the disclosures about the plan assets of a defined benefit pension or other postretirement plan. This FSP requires the disclosure of each major asset category at fair value using the fair value hierarchy in SFAS No. 157, Fair Value Measurements. Also, this FSP requires entities to disclose the net periodic benefit cost recognized for each annual period for which a statement of income is presented. This FSP is effective for annual statements beginning with 2009.

Table of Contents

Oil and Gas Operations (Unaudited)

In accordance with SFAS No. 69, Disclosures about Oil and Gas Producing Activities, and regulations of the U.S. Securities and Exchange Commission (SEC), we are making certain supplemental disclosures about our oil and gas exploration and production operations. While this information was developed with reasonable care and disclosed in good faith, we emphasize some of the data is necessarily imprecise and represents only approximate amounts because of the subjective judgments involved in developing such information. Accordingly, this information may not necessarily represent our current financial condition or our expected future results.

These disclosures include information about our consolidated oil and gas activities and our proportionate share of our equity affiliates oil and gas activities, covering both those in our Exploration and Production (E&P) segment, as well as in our LUKOIL Investment segment. As a result, amounts reported as Equity Affiliates in Oil and Gas Operations may differ from those shown in the individual segment disclosures reported elsewhere in this report. The data included for the LUKOIL Investment segment reflects the company s estimated share of OAO LUKOIL s amounts. Because LUKOIL s accounting cycle close and preparation of U.S. GAAP financial statements occur subsequent to our reporting deadline, our equity share of financial information and statistics for our LUKOIL investment are estimated based on current market indicators, publicly available LUKOIL information, and other objective data. Once the difference between actual and estimated results is known, an adjustment is recorded. Our estimated year-end 2008 reserves related to our equity investment in LUKOIL are based on LUKOIL s year-end 2008 reserve estimates and include adjustments to conform them to ConocoPhillips reserves policy.

Our proved reserves include estimated quantities related to production sharing contracts (PSCs), which are reported under the economic interest method and are subject to fluctuations in prices of crude oil, natural gas and natural gas liquids; recoverable operating expenses; and capital costs. If costs remain stable, reserve quantities attributable to recovery of costs will change inversely to changes in commodity prices. For example, if prices increase, then our applicable reserve quantities would decline. At December 31, 2008, approximately 14 percent of our total proved reserves, excluding LUKOIL, were under PSCs, primarily in our Asia Pacific geographic reporting area.

Our disclosures by geographic area for our consolidated operations include the United States, Canada, Europe (primarily Norway and the United Kingdom), Asia Pacific, Middle East and Africa, Russia and Caspian, and Other Areas (primarily South America). In these supplemental oil and gas disclosures, where we use equity accounting for operations that have proved reserves, these operations are shown separately and designated as Equity Affiliates, and include Canada, Asia Pacific, Middle East and Africa, Russia and Caspian, and Other Areas. Canada includes our share of the FCCL Oil Sands Partnership. Asia Pacific includes our share of Australia Pacific LNG s coalbed methane exploration and production activities. Middle East and Africa includes Qatargas 3. The Russia and Caspian area includes our share of Polar Lights Company, OOO Naryanmarneftegaz, and LUKOIL. Other Areas consists of the Petrozuata and Hamaca heavy-oil projects in Venezuela, which were expropriated on June 26, 2007.

On December 31, 2008, the SEC issued its final rules to modernize the supplemental oil and gas disclosures. Significant changes have occurred in our industry in the nearly three decades since the SEC first adopted its oil and gas disclosure rules, which include guidance on determining the volumetric measure of proved reserves. The new rules require the use of 12-month historical average prices using first-of-the-month pricing. The final rules also allow for companies to include nontraditional resources, such as bitumen extracted from oil sands, in their SEC-reported reserves. We expect to include Syncrude in our SEC proved reserves reporting as allowed under the new rules. We are currently evaluating the final rules and have not yet determined the overall impact

Table of Contents

to our proved reserve determinations. Our year-end 2009 reserve determinations and the oil and gas disclosures in our 2009 Form 10-K are expected to be subject to the new rules, based on current effective dates.

Reserves Governance

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

We have a companywide, comprehensive, SEC-compliant internal policy that governs the determination and reporting of proved reserves. This policy is applied by the geologists and reservoir engineers in our E&P business units around the world. As part of our internal control process, each business unit s reserves are reviewed annually by an internal team composed of reservoir engineers, geologists and finance personnel for adherence to SEC guidelines and company policy through on-site visits and review of documentation. In addition to providing independent reviews of the business units recommended reserve changes, this internal team also ensures reserves are calculated using consistent and appropriate standards and procedures. This team is independent of business unit line management and is responsible for reporting its findings to senior management and our internal audit group. The team is responsible for maintaining and communicating our reserves policy and procedures and is available for internal peer reviews and consultation on major projects or technical issues throughout the year. All of our proved crude oil, natural gas and natural gas liquids reserves held by consolidated companies and our share of equity affiliates have been estimated by ConocoPhillips, with assistance from third-party petroleum engineering consultants with regard to our equity interests in LUKOIL and Australia Pacific LNG.

During 2008, approximately 34 percent of our year-end 2007 E&P proved reserves were reviewed by an outside third-party petroleum engineering consulting firm. At the present time, we plan to continue to have an outside firm review a similar percentage of our reserve base during 2009.

Engineering estimates of the quantities of recoverable oil and gas reserves in oil and gas fields and in-place crude bitumen volumes in oil sand mining operations are inherently imprecise. See the Critical Accounting Estimates section of Management s Discussion and Analysis of Financial Condition and Results of Operations for additional discussion of the sensitivities surrounding these estimates.

Table of Contents

Proved Reserves Worldwide

Years Ended December 31	Alaska	Lower 48	Total U.S.	Canada	Europe	Asia Pacific	Middle East and Africa	Russia and Caspian	Other Areas	Total	Equity Affiliates
	Crude Oil Millions of Barrels Consolidated Operations										
Developed and Undeveloped											
End of 2005	1,505	170	1,675	44	808	274	328	190	17	3,336	2,430
Revisions	(118)	(11)	(129)	58	(65)	(12)	(18)	(74)	2	(238)	(35)
Improved recovery	13	1	14		5	63				82	
Purchases		181	181	16		13	42		17	269	393
Extensions and discoveries	53	9	62	4	6	8	3			83	74
Production	(97)	(37)	(134)	(9)	(90)	(39)	(39)		(3)	(314)	(171)
Sales		(18)	(18)							(18)	(1)
End of 2006	1,356	295	1,651	113	664	307	316	116	33	3,200	2,690
Revisions	24	19	43	28	10	(23)	(13)	1	(3)	43	202
Improved recovery	25	16	41							41	
Purchases											403
Extensions and discoveries	26	15	41	3	8	73	16			141	303
Production	(96)	(36)	(132)	(7)	(76)	(32)	(29)		(4)	(280)	(172)
Sales		(1)	(1)	(16)	(1)	(6)			(17)	(41)	(1,028)
End of 2007	1,335	308	1,643	121	605	319	290	117	9	3,104	2,398
Revisions	(189)	(40)	(229)	19	(17)	16	14	9		(188)	34
Improved recovery	23	5	28							28	
Purchases											2
Extensions and discoveries	13	21	34	2	9	13	5			63	88
Production	(90)	(33)	(123)	(9)	(77)	(33)	(28)		(3)	(273)	(164)
Sales								(11)		(11)	(41)
End of 2008	1,092	261	1,353	133	520	315	281	115	6	2,723	2,317
Equity affiliates											
End of 2005							46	1,295	1,089		2,430
End of 2006							60	1,607	1,023		2,690
End of 2007				623			70	1,705			2,398
End of 2008				700			70	1,547			2,317

Developed

Consolidated operations											
End of 2005	1,359	158	1,517	42	409	202	326			2,496	
End of 2006	1,254	281	1,535	50	359	181	292		13	2,430	
End of 2007	1,238	281	1,519	51	337	146	259		9	2,321	
End of 2008	994	227	1,221	56	316	170	263		6	2,032	
Equity affiliates											
End of 2005								1,013	472		1,485
End of 2006								1,293	369		1,662
End of 2007				45				1,336			1,381
End of 2008				105				1,211			1,316

Notable changes in proved crude oil reserves in the three years ending December 31, 2008, included:

Revisions: In 2008, revisions in Alaska were mainly due to lower prices at December 31, 2008, compared with December 31, 2007. In 2007 for our equity affiliate operations, revisions were primarily attributable to LUKOIL. In 2006, revisions in Alaska were primarily a result of reservoir performance.

Purchases: In 2007 for our equity affiliate operations, purchases reflect the formation of FCCL. In 2006, purchases in the Lower 48 were primarily related to our acquisition of Burlington Resources. In 2006 for our equity affiliate operations, purchases were mainly attributable to acquiring additional interests in LUKOIL.

Extensions and Discoveries: In 2007 for our equity affiliate operations, extensions and discoveries were primarily associated with FCCL.

Sales: In 2007 for our equity affiliates, sales were primarily due to the expropriation of our oil interests in Venezuela.

In addition to conventional crude oil, natural gas and natural gas liquids (NGL) proved reserves, we have proved oil sands mining reserves in Canada, associated with a Syncrude project totaling 249 million barrels at the end of 2008. For internal management purposes, we view these mining reserves and their development as part of our total exploration and production operations. However, SEC regulations currently in effect define these reserves as mining related. Therefore, they are not included in our tabular presentation of proved crude oil, natural gas and NGL reserves. These oil sands mining reserves also are not included in the standardized measure of discounted future net cash flows relating to proved oil and gas reserve quantities.

Natural Gas
Billions of Cubic Feet
Consolidated Operations

Years Ended December 31	Alaska	Lower 48	Total U.S.	Canada	Europe	Asia Pacific	Middle East and Africa	Russia and Caspian	Other Areas	Total	Equity Affiliates
Developed and Undeveloped											
End of 2005	3,472	4,114	7,586	970	3,062	3,700	1,061	129	5	16,513	2,548
Revisions	43	(87)	(44)	(123)	(293)	71	(64)	(31)	(39)	(523)	(310)
Improved recovery		4	4		1					5	
Purchases	6	5,258	5,264	2,466	432	25	94		129	8,410	325
Extensions and discoveries	23	551	574	353	64	6	58			1,055	925
Production	(130)	(770)	(900)	(356)	(414)	(233)	(62)		(6)	(1,971)	(99)
Sales		(43)	(43)							(43)	
End of 2006	3,414	9,027	12,441	3,310	2,852	3,569	1,087	98	89	23,446	3,389
Revisions	120	446	566	(41)	91	(47)	(26)		(12)	531	(327)
Improved recovery	5	1	6							6	
Purchases		30	30							30	
Extensions and discoveries	5	539	544	143	29	28	23			767	364
Production	(113)	(835)	(948)	(404)	(369)	(224)	(55)		(7)	(2,007)	(103)
Sales		(5)	(5)	(170)	(20)	(74)			(5)	(274)	(384)
End of 2007	3,431	9,203	12,634	2,838	2,583	3,252	1,029	98	65	22,499	2,939
Revisions	(852)	(270)	(1,122)	45	119	249	19	(1)		(691)	1,394
Improved recovery	15	2	17							17	
Purchases		13	13							13	598
Extensions and discoveries	2	273	275	118	45	3				441	37
Production	(108)	(788)	(896)	(385)	(391)	(249)	(51)		(5)	(1,977)	(118)
Sales		(1)	(1)	(2)	(53)	(17)		(9)	(60)	(142)	(62)
End of 2008	2,488	8,432	10,920	2,614	2,303	3,238	997	88		20,160	4,788
Equity affiliates											
End of 2005							1,063	1,197	288		2,548
End of 2006							1,573	1,429	387		3,389
End of 2007							1,925	1,014			2,939
End of 2008						594	1,925	2,269			4,788

Developed											
Consolidated operations											
End of 2005	3,316	3,966	7,282	918	2,393	2,600	1,060			14,253	
End of 2006	3,336	7,484	10,820	2,672	2,314	3,105	1,029		24	19,964	
End of 2007	3,344	7,417	10,761	2,328	2,177	2,857	963		26	19,112	
End of 2008	2,413	6,875	9,288	2,272	2,036	2,877	936			17,409	
Equity affiliates											
End of 2005								581	155		736
End of 2006								655	173		828
End of 2007								698			698
End of 2008						361		1,458			1,819

Natural gas production in the reserves table may differ from gas production (delivered for sale) in our statistics disclosure, primarily because the quantities above include gas consumed at the lease, but omit the gas equivalent of liquids extracted at any of our owned, equity-affiliate, or third-party processing plants or facilities.

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

Notable changes in proved natural gas reserves in the three years ended December 31, 2008, included:

> *Revisions*: In 2008, revisions in Alaska were mainly due to lower prices at December 31, 2008, compared with December 31, 2007. For our equity affiliate operations, revisions primarily resulted from a revised assessment of the reasonable certainty of project development and of the marketability of uncontracted gas volumes.

Table of Contents

Purchases: In 2008 for our equity affiliate operations, purchases relate to our Australia Pacific LNG joint venture with Origin Energy. In 2006 for our consolidated operations, purchases were primarily related to our acquisition of Burlington Resources.

Extensions and Discoveries: In 2006 for our equity affiliate operations, extensions and discoveries were primarily in Qatar and LUKOIL.

Natural Gas Liquids

Millions of Barrels

	Consolidated Operations										
Years Ended December 31	Alaska	Lower 48	Total U.S.	Canada	Europe	Asia Pacific	Middle East and Africa	Russia and Caspian	Other Areas	Total	Equity Affiliates
Developed and Undeveloped											
End of 2005	146	108	254	24	50	71	3			402	21
Revisions	(1)	24	23	1	(4)	(1)	(1)			18	
Improved recovery											
Purchases		328	328	56						384	
Extensions and discoveries		14	14	7						21	11
Production	(6)	(22)	(28)	(9)	(5)	(7)				(49)	
Sales		(2)	(2)							(2)	
End of 2006	139	450	589	79	41	63	2			774	32
Revisions	1	31	32	(4)		(2)				26	20
Improved recovery											
Purchases											
Extensions and discoveries		12	12	2	1	3				18	7
Production	(7)	(27)	(34)	(10)	(4)	(5)	(1)			(54)	
Sales				(2)		(3)				(5)	
End of 2007	133	466	599	65	38	56	1			759	59
Revisions	(17)	23	6	2	1	(1)	1			9	
Improved recovery											
Purchases											
Extensions and discoveries		4	4	2						6	1
Production	(6)	(28)	(34)	(9)	(7)	(6)	(1)			(57)	
Sales											
End of 2008	110	465	575	60	32	49	1			717	60
Equity affiliates											
End of 2005							21				21
End of 2006							32				32
End of 2007							39	20			59
End of 2008							39	21			60

Developed										
Consolidated operations										
End of 2005	146	106	252	23	31	64	2		372	
End of 2006	139	346	485	64	28	56	2		635	
End of 2007	133	343	476	53	33	54	1		617	
End of 2008	110	345	455	53	26	47	1		582	
Equity affiliates										
End of 2005										
End of 2006										
End of 2007								18		18
End of 2008								17		17

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

Notable changes in proved natural gas liquids reserves in the three years ended December 31, 2008, included:

Purchases: In 2006 for our consolidated operations, purchases were related to our acquisition of Burlington Resources.

152

Results of Operations

Year Ended December 31	Alaska	Lower 48	Total U.S.	Canada	Europe	Asia Pacific	Middle East and Africa	Russia and Caspian	Other Areas	Total	Equity Affiliates
	Millions of Dollars Consolidated Operations										
2008											
Sales	$ 5,771	6,726	12,497	4,386	8,061	4,787	1,895		290	31,916	6,104
Transfers	3,444	3,401	6,845		3,415	579	849			11,688	3,952
Other revenues	(25)	98	73	317	477	40	230	(56)	40	1,121	88
Total revenues	9,190	10,225	19,415	4,703	11,953	5,406	2,974	(56)	330	44,725	10,144
Production costs excluding taxes	960	1,405	2,365	887	1,157	436	257		34	5,136	955
Taxes other than income taxes	3,432	764	4,196	61	29	294	28	(1)	208	4,815	5,218
Exploration expenses	99	469	568	240	235	128	61	41	66	1,339	89
Depreciation, depletion and amortization	559	2,426	2,985	1,802	1,917	733	215	2	24	7,678	630
Impairments*		620	620	92	72	9				793	6,666
Transportation costs	409	519	928	140	302	115	29		10	1,524	1,010
Other related expenses	(38)	108	70	56	(306)	70	29	60	11	(10)	10
Accretion	40	59	99	33	196	14	4	3		349	4
	3,729	3,855	7,584	1,392	8,351	3,607	2,351	(161)	(23)	23,101	(4,438)
Provision for income taxes	1,317	1,310	2,627	371	5,241	1,640	2,094	(25)	(14)	11,934	633
Results of operations for producing activities	2,412	2,545	4,957	1,021	3,110	1,967	257	(136)	(9)	11,167	(5,071)
Other earnings	(97)	128	31	243	314	82	(71)	80	(25)	654	(274)
Net income (loss)	$ 2,315	2,673	4,988	1,264	3,424	2,049	186	(56)	(34)	11,821	(5,345)
Results of operations for producing activities of	$			286		4	(3)	(5,357)	(1)		(5,071)

equity affiliates

* *Excludes goodwill impairment of $25,443 million.*

	Millions of Dollars										
	Consolidated Operations										
Year Ended December 31	Alaska	Lower 48	Total U.S.	Canada	Europe	Asia Pacific	Middle East and Africa	Russia and Caspian	Other Areas	Total	Equity Affiliates
2007											
Sales*	$ 4,659	5,422	10,081	3,406	5,701	3,383	1,538		240	24,349	5,212
Transfers*	2,344	2,986	5,330		2,729	267	657			8,983	3,427
Other revenues	173	94	267	430	330	252	201	1	3	1,484	71
Total revenues	7,176	8,502	15,678	3,836	8,760	3,902	2,396	1	243	34,816	8,710
Production costs excluding taxes	775	1,232	2,007	874	1,029	410	251		41	4,612	906
Taxes other than income taxes	1,663	628	2,291	70	45	129	18	2	98	2,653	3,675
Exploration expenses	104	318	422	247	105	130	77	24	12	1,017	68
Depreciation, depletion and amortization	583	2,559	3,142	1,661	1,394	608	204			7,009	551
Impairments**	28	43	71	27	188	26			918	1,230	3,825
Transportation costs	412	553	965	137	335	101	24		64	1,626	770
Other related expenses	(64)	72	8	(96)	46	(26)	34	56	37	59	57
Accretion	37	48	85	47	132	9	3	1		277	7
	3,638	3,049	6,687	869	5,486	2,515	1,785	(82)	(927)	16,333	(1,149)
Provision for income taxes	1,248	1,091	2,339	237	3,595	982	1,545	(28)	1	8,671	844
Results of operations for producing activities	2,390	1,958	4,348	632	1,891	1,533	240	(54)	(928)	7,662	(1,993)
Other earnings	(135)	35	(100)	280	48	67	25	33	197	550	214
Net income (loss)	$ 2,255	1,993	4,248	912	1,939	1,600	265	(21)	(731)	8,212	(1,779)
Results of operations for producing activities of equity affiliates	$			98			(5)	1,554	(3,640)		(1,993)

* *Certain amounts in the Middle East and Africa were reclassified between sales and transfers. Total revenues were unchanged.*

** *Restated to align the portion of the expropriated assets impairment associated with Hamaca and Petrozuata from consolidated operations to equity affiliates.*

Table of Contents

	Millions of Dollars										
	Consolidated Operations										
Year Ended December 31	Alaska	Lower 48	Total U.S.	Canada	Europe	Asia Pacific	Middle East and Africa	Russia and Caspian	Other Areas	Total	Equity Affiliates
2006											
Sales*	$ 4,491	4,881	9,372	2,951	5,950	3,493	2,224		140	24,130	5,161
Transfers*	2,023	2,550	4,573		2,954	271	283			8,081	2,821
Other revenues	2	56	58	145	14	(8)	127		4	340	108
Total revenues	6,516	7,487	14,003	3,096	8,918	3,756	2,634		144	32,551	8,090
Production costs excluding taxes	708	893	1,601	706	814	324	215		27	3,687	739
Taxes other than income taxes	914	554	1,468	52	37	91	10	1	30	1,689	3,444
Exploration expenses	105	222	327	246	73	121	44	32	17	860	46
Depreciation, depletion and amortization	460	2,272	2,732	1,155	1,200	512	220	1	21	5,841	461
Impairments		15	15	131		10			19	175	
Transportation costs	610	555	1,165	104	316	89	18		10	1,702	420
Other related expenses	11	44	55	15	87	18	38	43	28	284	52
Accretion	34	36	70	39	97	8	2			216	6
	3,674	2,896	6,570	648	6,294	2,583	2,087	(77)	(8)	18,097	2,922
Provision for income taxes	1,409	1,064	2,473	(193)	4,578	1,061	1,931	(13)	(7)	9,830	891
Results of operations for producing activities	2,265	1,832	4,097	841	1,716	1,522	156	(64)	(1)	8,267	2,031
Other earnings	82	169	251	191	335	62	32	(4)	(25)	842	133
Net income (loss)	$ 2,347	2,001	4,348	1,032	2,051	1,584	188	(68)	(26)	9,109	2,164
Results of operations for producing activities of equity affiliates	$						(6)	1,229	808		2,031

*

Certain amounts in the Middle East and Africa were reclassified between sales and transfers. Total revenues were unchanged.

Results of operations for producing activities consist of all activities within the E&P organization and producing activities within the LUKOIL Investment segment, except for pipeline and marine operations, liquefied natural gas operations, our Canadian Syncrude operation, and crude oil and gas marketing activities, which are included in other earnings. Also excluded are our Midstream segment, downstream petroleum and chemical activities, as well as general corporate administrative expenses and interest.

Transfers are valued at prices that approximate market.

Other revenues include gains and losses from asset sales, certain amounts resulting from the purchase and sale of hydrocarbons, and other miscellaneous income.

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

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

Exploration expenses include dry hole costs, leasehold impairments, geological and geophysical expenses, the costs of retaining undeveloped leaseholds, and depreciation of support equipment and administrative expenses related to the exploration activity.

Depreciation, depletion and amortization (DD&A) in Results of Operations differs from that shown for total E&P in Note 26 Segment Disclosures and Related Information, in the Notes to Consolidated Financial Statements, mainly due to depreciation of support equipment being reclassified to production or exploration expenses, as applicable, in Results of Operations. In addition, other earnings include certain E&P activities, including their related DD&A charges.

Transportation costs include costs to transport our produced oil, natural gas or natural gas liquids to their points of sale, as well as processing fees paid to process natural gas to natural gas liquids. The profit element of transportation operations in which we have an ownership interest are deemed to be outside oil and gas producing activities. The net income of the transportation operations is included in other earnings.

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

The provision for income taxes is computed by adjusting each country s income before income taxes for permanent differences related to oil and gas producing activities that are reflected in our consolidated income tax expense for the period, multiplying the result by the country s statutory tax rate, and adjusting for applicable tax credits. Included in 2007 for Canada is a benefit related to the remeasurement of deferred tax liabilities from the 2007 Canadian graduated tax rate reduction. Included in 2006 for Canada is a $353 million benefit (which excludes $48 million related to the Syncrude oil project reflected in other earnings) related to the remeasurement of deferred tax liabilities from the 2006 Canadian graduated tax rate reduction and an Alberta provincial tax rate change. Europe income tax expense for 2006 was increased $250 million due to remeasurement of deferred tax liabilities as a result of increases in the U.K. tax rate.

Statistics

	2008	2007	2006
Net Production	Thousands of Barrels Daily		
Crude Oil			
Consolidated operations			
Alaska	**244**	261	263
Lower 48	**91**	102	104
United States	**335**	363	367
Canada	**25**	19	25
Europe	**214**	210	245
Asia Pacific	**91**	87	106
Middle East and Africa	**78**	81	106
Other areas	**9**	10	7
Total consolidated	**752**	770	856
Equity affiliates			
Canada	**30**	27	
Russia and Caspian	**410**	416	375
Other areas		42	101
Total equity affiliates	**440**	485	476
Natural Gas Liquids*			
Consolidated operations			
Alaska	**17**	19	17
Lower 48	**74**	79	62
United States	**91**	98	79
Canada	**25**	27	25
Europe	**19**	14	13
Asia Pacific	**16**	14	18
Middle East and Africa	**2**	2	1
Total consolidated	**153**	155	136

* *Represents amounts extracted attributable to E&P operations (see natural gas liquids reserves for further*

discussion). Includes for 2008, 2007 and 2006, 11,000, 14,000, and 11,000 barrels daily in Alaska, respectively, that were sold from the Prudhoe Bay lease to the Kuparuk lease for re-injection to enhance crude oil production.

	Millions of Cubic Feet Daily		
Natural Gas*			
Consolidated operations			
Alaska	**97**	110	145
Lower 48	**1,994**	2,182	2,028
United States	**2,091**	2,292	2,173
Canada	**1,054**	1,106	983
Europe	**954**	961	1,065
Asia Pacific	**609**	579	582
Middle East and Africa	**114**	125	142
Other areas	**14**	19	16
Total consolidated	**4,836**	5,082	4,961
Equity affiliates			
Russia and Caspian	**356**	256	244
Asia Pacific	**11**		
Other areas		5	9
Total equity affiliates	**367**	261	253

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

157

Average Sales Price	2008	2007	2006
Crude Oil Per Barrel			
Consolidated operations			
Alaska	$ **99.23**	69.75	62.66
Lower 48	**92.77**	63.49	57.04
United States	**97.47**	68.00	61.09
Canada	**80.18**	61.77	54.25
Europe	**95.73**	71.81	64.05
Asia Pacific	**91.47**	70.23	61.93
Middle East and Africa	**93.98**	72.18	66.59
Other areas	**84.74**	60.84	50.63
Total international	**93.30**	70.79	63.38
Total consolidated	**95.15**	69.47	62.39
Equity affiliates			
Canada	**58.54**	37.94	
Russia and Caspian	**61.48**	50.00	41.61
Other areas		47.46	46.40
Total equity affiliates	**61.28**	49.13	42.66
Natural Gas Liquids Per Barrel			
Consolidated operations			
Alaska	$ **94.29**	71.85	61.06
Lower 48	**52.28**	44.43	38.10
United States	**55.63**	46.00	40.35
Canada	**66.40**	50.85	45.62
Europe	**53.33**	45.72	38.78
Asia Pacific	**64.30**	53.19	43.95
Middle East and Africa	**8.51**	8.31	8.15
Total international	**59.70**	48.80	42.89
Total consolidated	**57.43**	47.13	41.50
Natural Gas Per Thousand Cubic Feet			
Consolidated operations			
Alaska	$ **4.38**	3.68	3.59
Lower 48	**7.71**	5.99	6.14
United States	**7.67**	5.98	6.11
Canada	**7.92**	6.09	5.67
Europe	**10.55**	7.87	7.78
Asia Pacific	**9.10**	6.37	5.91
Middle East and Africa	**1.09**	.80	.70
Other areas	**1.41**	1.18	1.31
Total international	**8.76**	6.51	6.27
Total consolidated	**8.28**	6.26	6.20

Equity affiliates			
Russia and Caspian	**1.06**	1.02	.57
Asia Pacific	**2.04**		
Other areas		.30	.30
Total equity affiliates	**1.10**	1.01	.57

		2008	2007	2006
Average Production Costs Per Barrel of Oil Equivalent				
Consolidated operations				
Alaska	$	**9.46**	7.12	6.38
Lower 48		**7.72**	6.20	4.85
United States		**8.34**	6.52	5.43
Canada		**10.74**	10.40	9.05
Europe		**8.06**	7.34	5.12
Asia Pacific		**5.71**	5.69	4.02
Middle East and Africa		**7.09**	6.62	4.51
Other areas		**8.20**	8.53	7.65
Total international		**8.08**	7.68	5.65
Total consolidated		**8.20**	7.13	5.55
Equity affiliates				
Canada		**16.58**	13.32	
Russia and Caspian		**4.46**	4.04	3.53
Asia Pacific		**5.96**		
Other areas			6.24	5.42
Total equity affiliates		**5.21**	4.70	3.91
Taxes Other Than Income Taxes Per Barrel of Oil Equivalent				
Consolidated operations				
Alaska	$	**33.83**	15.27	8.23
Lower 48		**4.20**	3.16	3.01
United States		**14.80**	7.45	4.98
Canada		**.74**	.83	.67
Europe		**.20**	.32	.23
Asia Pacific		**3.85**	1.79	1.13
Middle East and Africa		**.77**	.47	.21
Other areas		**50.14**	20.39	8.50
Total international		**1.81**	1.07	.60
Total consolidated		**7.69**	4.10	2.54
Equity affiliates				
Canada		**.27**	.21	
Russia and Caspian		**30.36**	20.89	21.40
Other areas			11.21	5.28
Total equity affiliates		**28.45**	19.05	18.21
Depreciation, Depletion and Amortization Per Barrel of Oil Equivalent				
Consolidated operations				
Alaska	$	**5.51**	5.35	4.14
Lower 48		**13.33**	12.87	12.35
United States		**10.53**	10.21	9.26

Canada	**21.82**	19.76	14.80
Europe	**13.36**	9.94	7.55
Asia Pacific	**9.61**	8.43	6.35
Middle East and Africa	**5.93**	5.38	4.61
Other areas	**5.79**		5.95
Total international	**13.69**	11.40	8.43
Total consolidated	**12.26**	10.84	8.80
Equity affiliates			
Canada	**7.65**	6.82	
Russia and Caspian	**3.13**	2.53	2.04
Asia Pacific	**13.41**		
Other areas		3.88	4.04
Total equity affiliates	**3.43**	2.86	2.43

	Productive			Dry		
Net Wells Completed*(1)*	**2008**	2007	2006	**2008**	2007	2006
Exploratory *(2)*						
Consolidated operations						
Alaska		3		**1**	1	1
Lower 48	**81**	71	27	**22**	9	9
United States	**81**	74	27	**23**	10	10
Canada	**49**	50	8	**36**	17	7
Europe	*****	1	1	**1**	1	1
Asia Pacific	**1**	4	2	*****	1	2
Middle East and Africa	*****		1	**1**	1	1
Russia and Caspian					*	
Other areas			1	**1**		*
Total consolidated	**131**	129	40	**62**	30	21
Equity affiliates						
Middle East and Africa			*			
Russia and Caspian	**1**			**1**		1
Asia Pacific				*****		
Total equity affiliates *(3)*	**1**		*	**1**		1
Includes step-out wells of:	***127***	*99*	*37*	***27***	*18*	*11*

	Productive			Dry		
	2008	2007	2006	**2008**	2007	2006
Development						
Consolidated operations						
Alaska	**47**	46	30			1
Lower 48	**690**	686	659	**8**	7	3
United States	**737**	732	689	**8**	7	4
Canada**	**465**	326	649	**32**	23	34
Europe	**10**	10	10			
Asia Pacific	**26**	17	15			
Middle East and Africa	**4**	7	7		*	
Russia and Caspian		*	*			
Other areas		5	11			
Total consolidated	**1,242**	1,097	1,381	**40**	30	38
Equity affiliates						
Canada	**148**	70			1	
Russia and Caspian	**7**	2	2			1
Asia Pacific	*****					
Other areas			15			

Total equity affiliates *(3)*	**155**	72	17		1	1

(1) Excludes farmout arrangements.

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

(3) Excludes LUKOIL.

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

** *Certain wells in 2007 and 2006 were* *reclassified from productive to dry.*

Table of Contents

			Productive *(2)*			
	In Progress *(1)*		Oil		Gas	
Wells at Year-End 2008	Gross	Net	Gross	Net	Gross	Net
Consolidated operations						
Alaska	24	13	1,941	869	29	19
Lower 48	524	350	12,846	5,030	25,616	16,614
United States	548	363	14,787	5,899	25,645	16,633
Canada	220*(3)*	154*(3)*	1,890	1,036	11,693	6,737
Europe	41	10	592	104	268	108
Asia Pacific	116	51	378	144	79	38
Middle East and Africa	36	6	1,086	193		
Russia and Caspian	30	3				
Other areas	3	1	93	41		
Total consolidated	994	588	18,826	7,417	37,685	23,516
Equity affiliates						
Canada	16	8	133	66	6	3
Russia and Caspian	12	4	83	30	2	1
Asia Pacific	311	89			389	119
Middle East and Africa	34	5				
Total equity affiliates *(4)*	373	106	216	96	397	123

(1) Includes wells that have been temporarily suspended.

(2) Includes 5,748 gross and 3,645 net multiple completion wells.

(3) Includes 154 gross and 116 net stratigraphic test wells related to heavy-oil projects.

(4) Excludes LUKOIL.

	Thousands of Acres			
	Developed		Undeveloped	
Acreage at December 31, 2008	Gross	Net	Gross	Net
Consolidated operations				
Alaska	647	328	2,900	2,036
Lower 48	7,887	5,487	13,384	9,691
United States	8,534	5,815	16,284	11,727
Canada	7,085	4,513	10,891	7,316
Europe	1,081	311	4,100	1,635
Asia Pacific	4,212	1,817	32,253	21,649
Middle East and Africa	2,466	449	12,790	2,258
Russia and Caspian			1,379	116
Other areas	1,001	444	11,561	9,517
Total consolidated	24,379	13,349	89,258	54,218
Equity affiliates				
Canada	57	25	483	193
Middle East and Africa			76	11
Russia and Caspian	290	90	1,175	476
Asia Pacific	178	50	10,088	3,948
Total equity affiliates*	525	165	11,822	4,628

* *Excludes LUKOIL.*

Table of Contents

Costs Incurred

	Millions of Dollars										
	Consolidated Operations										
	Alaska	Lower 48	Total U.S.	Canada	Europe	Asia Pacific	Middle East and Africa	Russia and Caspian	Other Areas	Total	Equity Affiliates
2008											
Unproved property acquisition	$ 514	505	1,019	195		5				1,219	4,544
Proved property acquisition		37	37							37	282
	514	542	1,056	195		5				1,256	4,826
Exploration	124	733	857	219	279	213	53	43	54	1,718	160
Development	823	2,458	3,281	1,387	2,056	1,314	175	612	7	8,832	2,625
	$ 1,461	3,733	5,194	1,801	2,335	1,532	228	655	61	11,806	7,611
Costs incurred of equity affiliates	$			576		4,775	194	2,066			7,611
2007*											
Unproved property acquisition	$ 5	202	207	117		122				446	2,135
Proved property acquisition		42	42							42	1,810
	5	244	249	117		122				488	3,945
Exploration	115	468	583	196	235	147	73	37	21	1,292	144
Development	567	2,375	2,942	1,252	1,871	1,275	355	462	73	8,230	2,506
	$ 687	3,087	3,774	1,565	2,106	1,544	428	499	94	10,010	6,595
Costs incurred of equity affiliates	$			4,117			334	2,093	51		6,595

2006

Unproved property acquisition	$	4	860	864	554	113		30		39	1,600	143
Proved property acquisition		13	15,784	15,797	8,296	1,169	525	856		252	26,895	2,647
		17	16,644	16,661	8,850	1,282	525	886		291	28,495	2,790
Exploration		131	332	463	182	172	231	57	47	27	1,179	58
Development		629	1,733	2,362	1,926	1,653	919	249	371	141	7,621	1,326
	$	777	18,709	19,486	10,958	3,107	1,675	1,192	418	459	37,295	4,174
Costs incurred of equity affiliates	$							183	3,854	137		4,174

* *Restated to include amounts omitted from equity affiliates in 2007 and to align certain amounts in the Middle East and Africa from consolidated operations to equity affiliates.*

Costs incurred include capitalized and expensed items.

Acquisition costs include the costs of acquiring proved and unproved oil and gas properties. In 2008, equity affiliate acquisition costs were due to the Australia Pacific LNG joint venture with Origin Energy. In 2007, equity affiliate acquisition costs were due to the FCCL business venture with EnCana. For 2006 consolidated operations, acquisition costs were primarily related to the Burlington Resources acquisition.

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

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

Table of Contents

Capitalized Costs

	Millions of Dollars										
	Consolidated Operations										
At December 31	Alaska	Lower 48	Total U.S.	Canada	Europe	Asia Pacific	Middle East and Africa	Russia and Caspian	Other Areas	Total	Equity Affiliates *
2008											
Proved properties	$ 10,880	31,592	42,472	15,237	17,025	9,269	2,922	2,508	566	89,999	15,361
Unproved properties	1,388	1,541	2,929	1,672	316	825	269	121	60	6,192	7,936
	12,268	33,133	45,401	16,909	17,341	10,094	3,191	2,629	626	96,191	23,297
Accumulated depreciation, depletion and amortization	4,642	10,974	15,616	5,672	8,622	2,810	1,025	5	528	34,278	8,271
	$ 7,626	22,159	29,785	11,237	8,719	7,284	2,166	2,624	98	61,913	15,026
Capitalized costs of equity affiliates	$			4,258		5,402	781	4,585			15,026
2007											
Proved properties	$ 10,182	28,645	38,827	17,330	20,615	8,014	2,758	2,135	641	90,320	12,707
Unproved properties	848	1,137	1,985	1,798	446	795	281	131	83	5,519	3,515
	11,030	29,782	40,812	19,128	21,061	8,809	3,039	2,266	724	95,839	16,222
Accumulated depreciation, depletion and amortization	4,158	7,920	12,078	4,875	9,374	2,155	822	4	504	29,812	1,008
	$ 6,872	21,862	28,734	14,253	11,687	6,654	2,217	2,262	220	66,027	15,214
Capitalized costs of equity affiliates*	$			4,771			649	9,794			15,214

* *Restated to include certain amounts that*

were omitted in 2007.

Capitalized costs include the cost of equipment and facilities for oil and gas producing activities. These costs include the activities of our E&P and LUKOIL Investment segments, excluding pipeline and marine operations, liquefied natural gas operations, our Canadian Syncrude operation, crude oil and natural gas marketing activities, and downstream operations.

Proved properties include capitalized costs for oil and gas leaseholds holding proved reserves, development wells and related equipment and facilities (including uncompleted development well costs), and support equipment.

Unproved properties include capitalized costs for oil and gas leaseholds under exploration (including where petroleum liquids and natural gas were found but determination of the economic viability of the required infrastructure is dependent upon further exploratory work under way or firmly planned) and for uncompleted exploratory well costs, including exploratory wells under evaluation.

Table of Contents

Standardized Measure of Discounted Future Net Cash Flows Relating to Proved Oil and Gas Reserve Quantities

Amounts are computed using year-end prices and costs (adjusted only for existing contractual changes), appropriate statutory tax rates and a prescribed 10 percent discount factor. Continuation of year-end economic conditions also is assumed. The calculation is based on estimates of proved reserves, which are revised over time as new data becomes available. Probable or possible reserves, which may become proved in the future, are not considered. The calculation also requires assumptions as to the timing of future production of proved reserves, and the timing and amount of future development, including dismantlement, and production costs.

While due care was taken in its preparation, we do not represent that this data is the fair value of our oil and gas properties, or a fair estimate of the present value of cash flows to be obtained from their development and production.

Table of Contents

Discounted Future Net Cash Flows

	Millions of Dollars										
	Consolidated Operations										
	Alaska	Lower 48	Total U.S.	Canada	Europe	Asia Pacific	Middle East and Africa	Russia and Caspian	Other Areas	Total	Equity Affiliates
2008											
Future cash inflows	$ 54,662	51,354	106,016	19,632	42,230	22,626	11,388	4,200	157	206,249	64,631
Less:											
Future production and transportation costs*	35,150	30,508	65,658	9,357	12,217	6,960	3,567	1,870	130	99,759	48,592
Future development costs	9,681	10,443	20,124	4,188	8,835	2,859	440	2,080	4	38,530	8,821
Future income tax provisions	3,227	3,439	6,666	401	11,679	4,880	6,082	246	2	29,956	891
Future net cash flows	6,604	6,964	13,568	5,686	9,499	7,927	1,299	4	21	38,004	6,327
10 percent annual discount	2,159	2,886	5,045	1,222	3,178	2,998	398	702	1	13,544	3,294
Discounted future net cash flows	$ 4,445	4,078	8,523	4,464	6,321	4,929	901	(698)	20	24,460	3,033
Discounted future net cash flows of equity affiliates	$			79		210	1,781	963			3,033
2007											
Future cash inflows	$ 133,909	94,706	228,615	30,125	83,367	46,520	31,509	11,272	803	432,211	163,555
Less:											
Future production and transportation costs*	75,024	41,945	116,969	11,206	15,781	11,996	3,884	1,876	706	162,418	97,375

Future development costs	8,392	9,690	18,082	4,605	10,920	3,958	400	2,761	34	40,760	10,847
Future income tax provisions	18,798	14,793	33,591	2,235	37,645	12,331	22,599	1,680	10	110,091	12,381
Future net cash flows	31,695	28,278	59,973	12,079	19,021	18,235	4,626	4,955	53	118,942	42,952
10 percent annual discount	16,510	12,158	28,668	3,870	5,776	7,113	1,847	4,504	2	51,780	22,925
Discounted future net cash flows	$ 15,185	16,120	31,305	8,209	13,245	11,122	2,779	451	51	67,162	20,027
Discounted future net cash flows of equity affiliates	$			3,889			4,453	11,685			20,027
2006											
Future cash inflows	$ 86,843	75,039	161,882	25,363	60,118	32,420	19,369	6,853	1,777	307,782	117,860
Less:											
Future production and transportation costs*	43,393	23,096	66,489	9,393	13,186	6,730	4,308	1,692	1,082	102,880	66,929
Future development costs	5,142	7,274	12,416	4,154	7,865	2,886	586	2,787	220	30,914	6,369
Future income tax provisions	14,138	14,357	28,495	2,313	25,627	9,204	12,029	590	101	78,359	16,085
Future net cash flows	24,170	30,312	54,482	9,503	13,440	13,600	2,446	1,784	374	95,629	28,477
10 percent annual discount	12,479	15,697	28,176	3,297	4,052	5,482	753	2,213	66	44,039	16,044
Discounted future net cash flows	$ 11,691	14,615	26,306	6,206	9,388	8,118	1,693	(429)	308	51,590	12,433
Discounted future net cash flows of	$						1,703	5,441	5,289		12,433

equity
affiliates

* *Includes taxes other than income taxes.*

Excludes discounted future net cash flows from Canadian Syncrude of $435 million in 2008, $4,484 million in 2007 and $2,220 million in 2006.

Table of Contents

Sources of Change in Discounted Future Net Cash Flows

	Millions of Dollars					
	Consolidated Operations			Equity Affiliates		
	2008	2007	2006	**2008**	2007	2006
Discounted future net cash flows at the beginning of the year	**$ 67,162**	51,590	53,948	**20,027**	12,433	16,659
Changes during the year						
Revenues less production and transportation costs for the year*	**(32,129)**	(24,441)	(25,133)	**(2,873)**	(3,288)	(3,379)
Net change in prices, and production and transportation costs*	**(73,497)**	49,447	(18,928)	**(22,541)**	10,082	(5,582)
Extensions, discoveries and improved recovery, less estimated future costs	**1,743**	6,985	3,867	**181**	2,188	401
Development costs for the year	**7,715**	7,289	7,020	**2,622**	2,346	1,327
Changes in estimated future development costs	**(3,129)**	(10,813)	(6,195)	**(813)**	(3,468)	(1,291)
Purchases of reserves in place, less estimated future costs	**10**	51	24,203	**321**	2,989	1,945
Sales of reserves in place, less estimated future costs	**(52)**	(1,347)	(506)	**(33)**	(9,619)	2
Revisions of previous quantity estimates**	**1,893**	(79)	(7,028)	**(1,689)**	3,855	107
Accretion of discount	**11,765**	8,561	9,759	**2,456**	1,809	2,215
Net change in income taxes	**42,979**	(20,081)	10,583	**5,375**	700	29
Total changes	**(42,702)**	15,572	(2,358)	**(16,994)**	7,594	(4,226)
Discounted future net cash flows at year end	**$ 24,460**	67,162	51,590	**3,033**	20,027	12,433

* *Includes taxes other than income taxes.*

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

The net change in prices, and production and transportation costs is the beginning-of-year reserve-production forecast multiplied by the net annual change in the per-unit sales price, and production and transportation cost, discounted at 10 percent.

Purchases and sales of reserves in place, along with extensions, discoveries and improved recovery, are calculated using production forecasts of the applicable reserve quantities for the year multiplied by the end-of-year sales prices, less future estimated costs, discounted at 10 percent.

The accretion of discount is 10 percent of the prior year s discounted future cash inflows, less future production, transportation and development costs.

The net change in income taxes is the annual change in the discounted future income tax provisions.

Table of Contents

Selected Quarterly Financial Data (Unaudited)

	Millions of Dollars				
	Sales and Other Operating Revenues*	Income (Loss) Before Income Taxes	Net Income (Loss)	Per Share of Common Stock Net Income (Loss) Basic	Diluted
2008					
First	**$ 54,883**	**7,549**	**4,139**	**2.65**	**2.62**
Second	**71,411**	**9,795**	**5,439**	**3.54**	**3.50**
Third	**70,044**	**9,467**	**5,188**	**3.43**	**3.39**
Fourth**	**44,504**	**(30,404)**	**(31,764)**	**(21.37)**	**(21.37)**
2007					
First	$ 41,320	6,066	3,546	2.15	2.12
Second***	47,370	3,518	301	.18	.18
Third	46,062	6,364	3,673	2.26	2.23
Fourth	52,685	7,324	4,371	2.75	2.71

* *Includes excise taxes on petroleum products sales.*

** *Includes noncash impairments relating to goodwill and to our LUKOIL investment that together amount to $32,853 million before- and after-tax.*

*** *Includes noncash impairment charge of $4,588 million before-tax, $4,512 million after-tax, for the* *expropriation of our Venezuelan oil interests.*

Table of Contents

Supplementary Information Condensed Consolidating Financial Information

We have various cross guarantees among ConocoPhillips, ConocoPhillips Company, ConocoPhillips Australia Funding Company, ConocoPhillips Canada Funding Company I, and ConocoPhillips Canada Funding Company II, with respect to publicly held debt securities. ConocoPhillips Company is wholly owned by ConocoPhillips. ConocoPhillips Australia Funding Company is an indirect, wholly owned subsidiary of ConocoPhillips Company. ConocoPhillips Canada Funding Company I and ConocoPhillips Canada Funding Company II are indirect, wholly owned subsidiaries of ConocoPhillips. ConocoPhillips and ConocoPhillips Company have fully and unconditionally guaranteed the payment obligations of ConocoPhillips Australia Funding Company, ConocoPhillips Canada Funding Company I, and ConocoPhillips Canada Funding Company II, with respect to their publicly held debt securities. Similarly, ConocoPhillips has fully and unconditionally guaranteed the payment obligations of ConocoPhillips Company with respect to its publicly held debt securities. In addition, ConocoPhillips Company has fully and unconditionally guaranteed the payment obligations of ConocoPhillips with respect to its publicly held debt securities. All guarantees are joint and several. The following condensed consolidating financial information presents the results of operations, financial position and cash flows for:

ConocoPhillips, ConocoPhillips Company, ConocoPhillips Australia Funding Company, ConocoPhillips Canada Funding Company I, and ConocoPhillips Canada Funding Company II (in each case, reflecting investments in subsidiaries utilizing the equity method of accounting).

All other nonguarantor subsidiaries of ConocoPhillips.

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

In April 2006, we filed a universal shelf registration statement with the SEC under which ConocoPhillips, as a well-known seasoned issuer, has the ability to issue and sell an indeterminate amount of various types of debt and equity securities, with certain debt securities guaranteed by ConocoPhillips Company. Also as part of that registration statement, ConocoPhillips Trust I and ConocoPhillips Trust II have the ability to issue and sell preferred trust securities, guaranteed by ConocoPhillips. ConocoPhillips Trust I and ConocoPhillips Trust II have not issued any trust-preferred securities under this registration statement, and thus have no assets or liabilities. Accordingly, columns for these two trusts are not included in the condensed consolidating financial information.

This condensed consolidating financial information should be read in conjunction with the accompanying consolidated financial statements and notes. Certain previously reported amounts appearing on the 2007 and 2006 statements of operations of ConocoPhillips Company have been reclassified between line items to conform to the current year presentation.

Table of Contents

	Millions of Dollars Year Ended December 31, 2008							
Statement of Operations	ConocoPhillips	ConocoPhillips Company	ConocoPhillips Australia Funding Company	ConocoPhillips Canada Funding Company I	ConocoPhillips Canada Funding Company II	All Other Subsidiaries	Consolidating Adjustments	Total Consolidated
Revenues and Other Income								
Sales and other operating revenues	$	153,695				87,147		240,842
Equity in earnings of affiliates	(16,789)	(12,073)				4,242	28,870	4,250
Other income (loss)	(3)	797				296		1,090
Intercompany revenues	26	3,390	86	85	52	30,348	(33,987)	
Total Revenues and Other Income	(16,766)	145,809	86	85	52	122,033	(5,117)	246,182
Costs and Expenses								
Purchased crude oil, natural gas and products		139,857				61,165	(32,359)	168,663
Production and operating expenses		5,028				6,910	(120)	11,818
Selling, general and administrative expenses	12	1,365				909	(57)	2,229
Exploration expenses		278				1,059		1,337
Depreciation, depletion and amortization		1,525				7,487		9,012
Impairments		9,863				24,676		34,539
Taxes other than income taxes		5,040				15,831	(234)	20,637
Accretion on discounted liabilities		59				359		418
Interest and debt expense	334	603	79	77	53	1,006	(1,217)	935
Foreign currency transaction losses (gains)		50		(254)	(295)	616		117
Minority interests						70		70
Total Costs and Expenses	346	163,668	79	(177)	(242)	120,088	(33,987)	249,775
Income (loss) before income taxes	(17,112)	(17,859)	7	262	294	1,945	28,870	(3,593)
Provision for income taxes	(114)	1,301	3	(10)	20	12,205		13,405
Net Income (Loss)	$ (16,998)	(19,160)	4	272	274	(10,260)	28,870	(16,998)

Statement of Operations	Year Ended December 31, 2007							
Revenues and Other Income								
Sales and other operating revenues	$	120,687				66,750		187,437
Equity in earnings of affiliates	12,071	9,800				3,025	(19,809)	5,087
Other income	4	505				1,462		1,971
Intercompany revenues	149	3,014	117	83	51	18,407	(21,821)	
Total Revenues and Other Income	12,224	134,006	117	83	51	89,644	(41,630)	194,495
Costs and Expenses								
Purchased crude oil, natural gas and products		103,516				38,880	(18,967)	123,429
Production and operating expenses		4,522				6,247	(86)	10,683
Selling, general and administrative expenses	17	1,407				943	(61)	2,306
Exploration expenses		111				896		1,007
Depreciation, depletion and amortization		1,476				6,822		8,298
Impairments		1,852				3,178		5,030
Taxes other than income taxes		5,463				13,802	(275)	18,990
Accretion on discounted liabilities		55				286		341
Interest and debt expense	423	1,758	109	77	53	1,265	(2,432)	1,253
Foreign currency transaction losses (gains)		12		166	124	(503)		(201)
Minority interests						87		87
Total Costs and Expenses	440	120,172	109	243	177	71,903	(21,821)	171,223
Income (loss) before income taxes	11,784	13,834	8	(160)	(126)	17,741	(19,809)	23,272
Provision for income taxes	(107)	2,810	3	16	6	8,653		11,381
Net Income (Loss)	$ 11,891	11,024	5	(176)	(132)	9,088	(19,809)	11,891

	Millions of Dollars							
	Year Ended December 31, 2006							
Statement of Operations	ConocoPhillips	ConocoPhillips Company	ConocoPhillips Australia Funding Company	ConocoPhillips Canada Funding Company I	ConocoPhillips Canada Funding Company II	All Other Subsidiaries	Consolidating Adjustments	Total Consolidated
Revenues and Other Income								
Sales and other operating revenues	$	117,063				66,587		183,650
Equity in earnings of affiliates	15,798	11,136				3,608	(26,354)	4,188
Other income		605				80		685
Intercompany revenues	173	2,599	94	17	10	15,740	(18,633)	
Total Revenues and Other Income	15,971	131,403	94	17	10	86,015	(44,987)	188,523
Costs and Expenses								
Purchased crude oil, natural gas and products		97,986				37,735	(16,822)	118,899
Production and operating expenses		4,720				5,782	(89)	10,413
Selling, general and administrative expenses	19	1,593				914	(50)	2,476
Exploration expenses		120				714		834
Depreciation, depletion and amortization		1,702				5,582		7,284
Impairments		410				273		683
Taxes other than income taxes		5,877				12,577	(267)	18,187
Accretion on discounted liabilities		58				223		281
Interest and debt expense	537	1,338	80	17	11	509	(1,405)	1,087
Foreign currency transaction (gains) losses		(2)		(39)	(37)	48		(30)
Minority interests						76		76
Total Costs and Expenses	556	113,802	80	(22)	(26)	64,433	(18,633)	160,190
Income before income taxes	15,415	17,601	14	39	36	21,582	(26,354)	28,333
Provision for income taxes	(135)	2,839	5	10	10	10,054		12,783

Net Income	$ 15,550	14,762	9	29	26	11,528	(26,354)	15,550

	Millions of Dollars							
	At December 31, 2008							
Balance Sheet	ConocoPhillips	ConocoPhillips Company	ConocoPhillips Australia Funding Company	ConocoPhillips Canada Funding Company I	ConocoPhillips Canada Funding Company II	All Other Subsidiaries	Consolidating Adjustments	Total Consolidated
Assets								
Cash and cash equivalents	$	8		10	1	750	(14)	755
Accounts and notes receivable	13	10,541	15			21,314	(19,888)	11,995
Inventories		2,909				2,287	(101)	5,095
Prepaid expenses and other current assets	10	1,170		14	10	1,794		2,998
Total Current Assets	23	14,628	15	24	11	26,145	(20,003)	20,843
Investments, loans and long-term receivables*	61,144	83,645	1,699	1,183	802	44,629	(160,203)	32,899
Net properties, plants and equipment		19,017				64,928	2	83,947
Goodwill		3,778						3,778
Intangibles		784				62		846
Other assets	13	243	2	109	183	286	(284)	552
Total Assets	$ 61,180	122,095	1,716	1,316	996	136,050	(180,488)	142,865
Liabilities and Stockholders Equity								
Accounts payable	$	17,566		2	1	16,309	(19,888)	13,990
Short-term debt		301	950			68	(949)	370
Accrued income and other taxes		233		(1)	(1)	4,042		4,273
Employee benefit obligations		702				237		939
Other accruals	25	883	18	15	10	1,280	(23)	2,208
Total Current Liabilities	25	19,685	968	16	10	21,936	(20,860)	21,780
Long-term debt	7,703	5,364	749	1,250	848	10,221	950	27,085
Asset retirement obligations and accrued environmental costs		1,101				6,062		7,163
Joint venture acquisition obligation						5,669		5,669
Deferred income taxes	(4)	2,882		9	34	15,258	(12)	18,167
Employee benefit obligations		3,367				760		4,127
Other liabilities and deferred credits*	4,954	24,609				16,976	(43,930)	2,609
Total Liabilities	12,678	57,008	1,717	1,275	892	76,882	(63,852)	86,600
Minority interests						1,100		1,100
Retained earnings	24,130	4,792	(3)	125	167	7,234	(5,803)	30,642

Other stockholders equity	24,372	60,295	2	(84)	(63)	50,834	(110,833)	24,523
Total	$ 61,180	122,095	1,716	1,316	996	136,050	(180,488)	142,865

* *Includes intercompany loans.*

Balance Sheet				At December 31, 2007				
Assets								
Cash and cash equivalents	$	195		7	1	1,626	(373)	1,456
Accounts and notes receivable	40	12,421	15	12	4	19,548	(15,686)	16,354
Inventories		2,043				2,190	(10)	4,223
Prepaid expenses and other current assets	9	578		1		2,114		2,702
Total Current Assets	49	15,237	15	20	5	25,478	(16,069)	24,735
Investments, loans and long-term receivables*	86,942	57,936	1,700	1,470	997	18,972	(134,689)	33,328
Net properties, plants and equipment		17,677				71,317	9	89,003
Goodwill		12,746				16,590		29,336
Intangibles		808				88		896
Other assets	8	153	3	5	4	520	(234)	459
Total Assets	$ 86,999	104,557	1,718	1,495	1,006	132,965	(150,983)	177,757
Liabilities and Stockholders Equity								
Accounts payable	$ 6	18,792		10	4	15,108	(16,059)	17,861
Short-term debt	1,000	309				89		1,398
Accrued income and other taxes		601			(1)	4,117	97	4,814
Employee benefit obligations		509				411		920
Other accruals	21	594	20	16	11	1,230	(3)	1,889
Total Current Liabilities	1,027	20,805	20	26	14	20,955	(15,965)	26,882
Long-term debt	3,402	5,694	1,699	1,250	848	7,396		20,289
Asset retirement obligations and accrued environmental costs		1,167				6,094		7,261
Joint venture acquisition obligation						6,294		6,294
Deferred income taxes	(3)	3,050		32	18	17,907	14	21,018
Employee benefit obligations		2,292				899		3,191
Other liabilities and deferred credits*	42	16,447		132	102	15,489	(29,546)	2,666
Total Liabilities	4,468	49,455	1,719	1,440	982	75,034	(45,497)	87,601
Minority interests		(19)				1,194	(2)	1,173
Retained earnings	43,988	23,952	(1)	(147)	(107)	20,738	(37,913)	50,510
Other stockholders equity	38,543	31,169		202	131	35,999	(67,571)	38,473
Total	$ 86,999	104,557	1,718	1,495	1,006	132,965	(150,983)	177,757

* *Includes intercompany loans.*

Table of Contents

	Millions of Dollars							
	Year Ended December 31, 2008							
Statement of Cash Flows	ConocoPhillips	ConocoPhillips Company	ConocoPhillips Australia Funding Company	ConocoPhillips Canada Funding Company I	ConocoPhillips Canada Funding Company II	All Other Subsidiaries	Consolidating Adjustments	Total Consolidated
Cash Flows From Operating Activities								
Net Cash Provided by Operating Activities	$ 12,641	2,077	6	3		10,815	(2,884)	22,658
Cash Flows From Investing Activities								
Capital expenditures and investments		(5,131)				(14,848)	880	(19,099)
Proceeds from asset dispositions		271				1,549	(180)	1,640
Long-term advances/loans related parties	(5,000)	(5,815)				(3,396)	14,048	(163)
Collection of advances/loans related parties		293				17	(276)	34
Other		(8)				(20)		(28)
Net Cash Used in Investing Activities	(5,000)	(10,390)				(16,698)	14,472	(17,616)
Cash Flows From Financing Activities								
Issuance of debt	4,779	8,266				8,660	(14,048)	7,657
Repayment of debt	(1,500)	(361)				(312)	276	(1,897)
Issuance of company common stock	198							198
Repurchase of company common stock	(8,249)							(8,249)
Dividends paid on common stock	(2,854)		(6)			(3,237)	3,243	(2,854)
Other	(15)	134				(38)	(700)	(619)
Net Cash Provided by (Used in) Financing Activities	(7,641)	8,039	(6)			5,073	(11,229)	(5,764)

Effect of Exchange Rate Changes on Cash and Cash Equivalents		87				(66)		21
Net Change in Cash and Cash Equivalents		(187)		3		(876)	359	(701)
Cash and cash equivalents at beginning of year		195		7	1	1,626	(373)	1,456
Cash and Cash Equivalents at End of Year	$	8		10	1	750	(14)	755
Statement of Cash Flows	Year Ended December 31, 2007							
Cash Flows From Operating Activities								
Net Cash Provided by Operating Activities	$ 14,984	9,944	10	7		26,021	(26,416)	24,550
Cash Flows From Investing Activities								
Capital expenditures and investments		(2,967)				(9,121)	297	(11,791)
Proceeds from asset dispositions		1,391				3,029	(848)	3,572
Long-term advances/loans related parties		(491)				(2,649)	2,458	(682)
Collection of advances/loans related parties		1,238	300			837	(2,286)	89
Other	1	83				166		250
Net Cash Provided by (Used in) Investing Activities	1	(746)	300			(7,738)	(379)	(8,562)
Cash Flows From Financing Activities								
Issuance of debt	(39)	2,179				1,253	(2,458)	935
Repayment of debt	(5,564)	(1,385)	(300)			(1,491)	2,286	(6,454)
Issuance of company common stock	285							285
Repurchase of company common stock	(7,001)							(7,001)
Dividends paid on common stock	(2,661)	(10,000)	(10)			(16,376)	26,386	(2,661)
Other	(5)	87				(1,076)	550	(444)

Net Cash Used in Financing Activities	(14,985)	(9,119)	(310)			(17,690)	26,764	(15,340)
Effect of Exchange Rate Changes on Cash and Cash Equivalents						(9)		(9)
Net Change in Cash and Cash Equivalents		79		7		584	(31)	639
Cash and cash equivalents at beginning of year		116			1	1,042	(342)	817
Cash and Cash Equivalents at End of Year	$	195		7	1	1,626	(373)	1,456

172

Table of Contents

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

Activities						
Effect of Exchange Rate Changes on Cash and Cash Equivalents				15		15
Net Change in Cash and Cash Equivalents	(497)		1	(559)	(342)	(1,397)
Cash and cash equivalents at beginning of year	613			1,601		2,214
Cash and Cash Equivalents at End of Year	$ 116		1	1,042	(342)	817

173

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

None.

Item 9A. CONTROLS AND PROCEDURES

As of December 31, 2008, with the participation of our management, our Chairman and Chief Executive Officer (principal executive officer) and our Senior Vice President, Finance, and Chief Financial Officer (principal financial officer) carried out an evaluation, pursuant to Rule 13a-15(b) of the Securities Exchange Act of 1934, as amended (the Act), of the effectiveness of the design and operation of ConocoPhillips disclosure controls and procedures (as defined in Rule 13a-15(e) of the Act). Based upon that evaluation, our Chairman and Chief Executive Officer and our Senior Vice President, Finance, and Chief Financial Officer concluded that our disclosure controls and procedures were operating effectively as of December 31, 2008.

There have been no changes in our internal control over financial reporting, as defined in Rule 13a-15(f) of the Act, in the quarterly period ended December 31, 2008, that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

Management s Annual Report on Internal Control Over Financial Reporting

This report is included in Item 8 on page 78 and is incorporated herein by reference.

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

This report is included in Item 8 on page 80 and is incorporated herein by reference.

Item 9B. OTHER INFORMATION

None.

Table of Contents

PART III

Item 10. DIRECTORS, EXECUTIVE OFFICERS AND CORPORATE GOVERNANCE

Information regarding our executive officers appears in Part I of this report on page 30.

Code of Business Ethics and Conduct for Directors and Employees

We have a Code of Business Ethics and Conduct for Directors and Employees (Code of Ethics), including our principal executive officer, principal financial officer, principal accounting officer and persons performing similar functions. We have posted a copy of our Code of Ethics on the Corporate Governance section of our Internet Web site at *www.conocophillips.com* (within the Investor Relations>Governance section as accessed through the Site Map link on the home page). Any waivers of the Code of Ethics must be approved, in advance, by our full Board of Directors. Any amendments to, or waivers from, the Code of Ethics that apply to our executive officers and directors will be posted on the Corporate Governance section of our Internet Web site.

All other information required by Item 10 of Part III will be included in our Proxy Statement relating to our 2009 Annual Meeting of Stockholders, to be filed pursuant to Regulation 14A on or before April 30, 2009, and is incorporated herein by reference.*

Item 11. EXECUTIVE COMPENSATION

Information required by Item 11 of Part III will be included in our Proxy Statement relating to our 2009 Annual Meeting of Stockholders, to be filed pursuant to Regulation 14A on or before April 30, 2009, and is incorporated herein by reference.*

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

Information required by Item 12 of Part III will be included in our Proxy Statement relating to our 2009 Annual Meeting of Stockholders, to be filed pursuant to Regulation 14A on or before April 30, 2009, and is incorporated herein by reference.*

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

Information required by Item 13 of Part III will be included in our Proxy Statement relating to our 2009 Annual Meeting of Stockholders, to be filed pursuant to Regulation 14A on or before April 30, 2009, and is incorporated herein by reference.*

Item 14. PRINCIPAL ACCOUNTING FEES AND SERVICES

Information required by Item 14 of Part III will be included in our Proxy Statement relating to our 2009 Annual Meeting of Stockholders, to be filed pursuant to Regulation 14A on or before April 30, 2009, and is incorporated herein by reference.*

* *Except for information or data specifically incorporated herein by reference under Items 10 through 14, other information and data appearing in our 2009 Proxy Statement are not deemed to be a part of*

this Annual Report on Form 10-K or deemed to be filed with the Commission as a part of this report.

Table of Contents

PART IV

Item 15. EXHIBITS, FINANCIAL STATEMENT SCHEDULES

(a) 1. Financial Statements and Supplementary Data

The financial statements and supplementary information listed in the Index to Financial Statements, which appears on page 77, are filed as part of this annual report.

2. Financial Statement Schedules

Schedule II - Valuation and Qualifying Accounts, appears below. All other schedules are omitted because they are not required, not significant, not applicable or the information is shown in another schedule, the financial statements or the notes to consolidated financial statements.

3. Exhibits

The exhibits listed in the Index to Exhibits, which appears on pages 177 through 180, are filed as part of this annual report.

(c) If required, financial statements of OAO LUKOIL will be filed by amendment to this Annual Report on Form 10-K no later than June 30, 2009, in accordance with Rule 3.09 of Regulation S-X.

SCHEDULE II VALUATION AND QUALIFYING ACCOUNTS (Consolidated)
ConocoPhillips

	Millions of Dollars				
Description	Balance at January 1	Charged to Expense	Other (a)	Deductions	Balance at December 31
2008					
Deducted from asset accounts:					
Allowance for doubtful accounts and notes receivable	**$ 58**	**38**	**(4)**	**(31)(b)**	**61**
Deferred tax asset valuation allowance	**1,269**	**220**	**1**	**(150)**	**1,340**
Included in other liabilities:					
Restructuring accruals	**117**	**125**	**11**	**(57)(c)**	**196**
2007					
Deducted from asset accounts:					
Allowance for doubtful accounts and notes receivable	$ 45	23	(2)	(8)(b)	58
Deferred tax asset valuation allowance	822	67	417	(37)	1,269
Included in other liabilities:					
Restructuring accruals	164	31	5	(83)(c)	117
2006					
Deducted from asset accounts:					
Allowance for doubtful accounts and notes receivable	$ 72	11	9	(47)(b)	45

Deferred tax asset valuation allowance	850	103	42	(173)	822
Included in other liabilities:					
Restructuring accruals	53	10	216	(115)(c)	164

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

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

(c) *Benefit payments.*

CONOCOPHILLIPS
INDEX TO EXHIBITS

Exhibit Number	Description
2.1	Agreement and Plan of Merger, dated as of November 18, 2001, by and among ConocoPhillips Company (formerly named Phillips Petroleum Company), ConocoPhillips (formerly named CorvettePorsche Corp.), P Merger Corp. (formerly named Porsche Merger Corp.), C Merger Corp. (formerly named Corvette Merger Corp.) and ConocoPhillips Holding Company (formerly named Conoco Inc.) (Holding) (incorporated by reference to Annex A to the Joint Proxy Statement/Prospectus included in ConocoPhillips Registration Statement on Form S-4; Registration No. 333-74798).
2.2	Agreement and Plan of Merger, dated as of December 12, 2005, by and among ConocoPhillips, Cello Acquisition Corp. and Burlington Resources Inc. (incorporated by reference to Exhibit 2.1 to the Current Report of ConocoPhillips on Form 8-K filed on December 14, 2005; File No. 001-32395).
3.1	Amended and Restated Certificate of Incorporation (incorporated by reference to Exhibit 3.1 to the Quarterly Report of ConocoPhillips on Form 10-Q for the quarterly period ended June 30, 2008; File No. 001-32395).
3.2	Certificate of Designations of Series A Junior Participating Preferred Stock of ConocoPhillips (incorporated by reference to Exhibit 3.2 to the Current Report of ConocoPhillips on Form 8-K filed on August 30, 2002; File No. 000-49987).
3.3	By-Laws of ConocoPhillips, as amended on December 12, 2008 (incorporated by reference to Exhibit 3.1 to the Current Report of ConocoPhillips on Form 8-K filed on December 12, 2008; File No. 001-32395).
4.1	Rights agreement, dated as of June 30, 2002, between ConocoPhillips and Mellon Investor Services LLC, as rights agent, which includes as Exhibit A the form of Certificate of Designations of Series A Junior Participating Preferred Stock, as Exhibit B the form of Rights Certificate and as Exhibit C the Summary of Rights to Purchase Preferred Stock (incorporated by reference to Exhibit 4.1 to the Current Report of ConocoPhillips on Form 8-K filed on August 30, 2002; File No. 000-49987).
	ConocoPhillips and its subsidiaries are parties to several debt instruments under which the total amount of securities authorized does not exceed 10 percent of the total assets of ConocoPhillips and its subsidiaries on a consolidated basis. Pursuant to paragraph 4(iii)(A) of Item 601(b) of Regulation S-K, ConocoPhillips agrees to furnish a copy of such instruments to the SEC upon request.
10.1	Shareholder Agreement, dated September 29, 2004, by and between LUKOIL and ConocoPhillips (incorporated by reference to Exhibit 99.2 of the Current Report of ConocoPhillips on Form 8-K filed on September 30, 2004; File No. 333-74798).
10.2	

1986 Stock Plan of Phillips Petroleum Company (incorporated by reference to Exhibit 10.11 to the Annual Report of ConocoPhillips on Form 10-K for the year ended December 31, 2002; File No. 000-49987).

Table of Contents

Exhibit Number	Description
10.3	1990 Stock Plan of Phillips Petroleum Company (incorporated by reference to Exhibit 10.12 to the Annual Report of ConocoPhillips on Form 10-K for the year ended December 31, 2002; File No. 000-49987).
10.4	Annual Incentive Compensation Plan of Phillips Petroleum Company (incorporated by reference to Exhibit 10.13 to the Annual Report of ConocoPhillips on Form 10-K for the year ended December 31, 2002; File No. 000-49987).
10.5	Incentive Compensation Plan of Phillips Petroleum Company (incorporated by reference to Exhibit 10(g) to the Annual Report of ConocoPhillips Company on Form 10-K for the year ended December 31, 1999; File No. 1-720).
10.6	ConocoPhillips Supplemental Executive Retirement Plan (incorporated by reference to Exhibit 10.7 to the Annual Report of ConocoPhillips on Form 10-K for the year ended December 31, 2005; File No. 001-32395).
10.7	Non-Employee Director Retirement Plan of Phillips Petroleum Company (incorporated by reference to Exhibit 10.18 to the Annual Report of ConocoPhillips on Form 10-K for the year ended December 31, 2002; File No. 000-49987).
10.8	Omnibus Securities Plan of Phillips Petroleum Company (incorporated by reference to Exhibit 10.19 to the Annual Report of ConocoPhillips on Form 10-K for the year ended December 31, 2002; File No. 000-49987).
10.9	Key Employee Missed Credited Service Retirement Plan of ConocoPhillips (incorporated by reference to Exhibit 10.10 to the Annual Report of ConocoPhillips on Form 10-K for the year ended December 31, 2005; File No. 001-32395).
10.10	Phillips Petroleum Company Stock Plan for Non-Employee Directors (incorporated by reference to Exhibit 10.22 to the Annual Report of ConocoPhillips on Form 10-K for the year ended December 31, 2002; File No. 000-49987).
10.11	ConocoPhillips Key Employee Supplemental Retirement Plan.
10.12.1	Defined Contribution Make-Up Plan of ConocoPhillips Title I (incorporated by reference to Exhibit 10.13.1 to the Annual Report of ConocoPhillips on Form 10-K for the year ended December 31, 2005; File No. 001-32395).
10.12.2	Defined Contribution Make-Up Plan of ConocoPhillips Title II.
10.13	2002 Omnibus Securities Plan of Phillips Petroleum Company (incorporated by reference to Exhibit 10.26 to the Annual Report of ConocoPhillips on Form 10-K for the year ended December 31, 2002; File No. 000-49987).
10.14	

1998 Stock and Performance Incentive Plan of ConocoPhillips (incorporated by reference to Exhibit 10.27 to the Annual Report of ConocoPhillips on Form 10-K for the year ended December 31, 2002; File No. 000-49987).

Table of Contents

Exhibit Number	Description
10.15	1998 Key Employee Stock Performance Plan of ConocoPhillips (incorporated by reference to Exhibit 10.28 to the Annual Report of ConocoPhillips on Form 10-K for the year ended December 31, 2002; File No. 000-49987).
10.16	Deferred Compensation Plan for Non-Employee Directors of ConocoPhillips (incorporated by reference to Exhibit 10.17 to the Annual Report of ConocoPhillips on Form 10-K for the year ended December 31, 2005; File No. 001-32395).
10.17	ConocoPhillips Form Indemnity Agreement with Directors (incorporated by reference to Exhibit 10.34 to the Annual Report of ConocoPhillips on Form 10-K for the year ended December 31, 2002; File No. 000-49987).
10.18	Rabbi Trust Agreement dated December 17, 1999 (incorporated by reference to Exhibit 10.11 of Holding s Form 10-K for the year ended December 31, 1999; File No. 001-14521).
10.18.1	Amendment to Rabbi Trust Agreement dated February 25, 2002 (incorporated by reference to Exhibit 10.39.1 to the Annual Report of ConocoPhillips on Form 10-K for the year ended December 31, 2002; File No. 000-49987).
10.19	ConocoPhillips Directors Charitable Gift Program (incorporated by reference to Exhibit 10.40 to the Annual Report of ConocoPhillips on Form 10-K for the year ended December 31, 2003; File No. 000-49987).
10.19.1	First and Second Amendments to the ConocoPhillips Directors Charitable Gift Program (incorporated by reference to Exhibit 10 to the Quarterly Report of ConocoPhillips on Form 10-Q for the quarterly period ended June 30, 2008; File No. 001-32395).
10.20	ConocoPhillips Matching Gift Plan for Directors and Executives (incorporated by reference to Exhibit 10.41 to the Annual Report of ConocoPhillips on Form 10-K for the year ended December 31, 2003; File No. 000-49987).
10.21.1	Key Employee Deferred Compensation Plan of ConocoPhillips Title I (incorporated by reference to Exhibit 10.23.1 to the Annual Report of ConocoPhillips on Form 10-K for the year ended December 31, 2005; File No. 001-32395).
10.21.2	Key Employee Deferred Compensation Plan of ConocoPhillips Title II.
10.22	ConocoPhillips Key Employee Change in Control Severance Plan.
10.23	ConocoPhillips Executive Severance Plan.
10.24	2004 Omnibus Stock and Performance Incentive Plan of ConocoPhillips (incorporated by reference to Appendix C of ConocoPhillips Proxy Statement on Schedule 14A relating to the 2004 Annual Meeting of Shareholders; File No. 000-49987).

10.25	Aircraft Time Sharing Agreement by and between James J. Mulva and ConocoPhillips (incorporated by reference to Exhibit 10 of the Quarterly Report of ConocoPhillips on Form 10-Q for the quarterly period ended June 30, 2007; File No. 001-32395).

Table of Contents

Exhibit Number	Description
10.26	Form of Stock Option Award Agreement under the ConocoPhillips Stock Option and Stock Appreciation Rights Program.
10.27	Form of Restricted Stock Unit Award Agreement under the ConocoPhillips Performance Share Program.
10.28	Omnibus Amendments to certain ConocoPhillips employee benefit plans, adopted December 7, 2007 (incorporated by reference to Exhibit 10.30 to the Annual Report of ConocoPhillips on Form 10-K for the year ended December 31, 2007; File No. 001-32395).
10.29	Letter Agreement between ConocoPhillips and John E. Lowe, dated October 1, 2008 (incorporated by reference to Exhibit 99.1 to the Current Report of ConocoPhillips on Form 8-K filed on October 1, 2008; File No. 001-32395).
10.30	Annex to Nonqualified Deferred Compensation Arangements of ConocoPhillips.
12	Computation of Ratio of Earnings to Fixed Charges.
21	List of Subsidiaries of ConocoPhillips.
23	Consent of Independent Registered Public Accounting Firm.
31.1	Certification of Chief Executive Officer pursuant to Rule 13a-14(a) under the Securities Exchange Act of 1934.
31.2	Certification of Chief Financial Officer pursuant to Rule 13a-14(a) under the Securities Exchange Act of 1934.
32	Certifications pursuant to 18 U.S.C. Section 1350.

Table of Contents

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized.

CONOCOPHILLIPS

February 25, 2009

/s/ James J. Mulva
James J. Mulva
Chairman of the Board of Directors
and Chief Executive Officer

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed, as of February 25, 2009, on behalf of the registrant by the following officers in the capacity indicated and by a majority of directors.

Signature	Title
/s/ James J. Mulva *James J. Mulva*	Chairman of the Board of Directors and Chief Executive Officer (Principal executive officer)
/s/ Sigmund L. Cornelius *Sigmund L. Cornelius*	Senior Vice President, Finance, and Chief Financial Officer (Principal financial officer)
/s/ Rand C. Berney *Rand C. Berney*	Vice President and Controller (Principal accounting officer)

Table of Contents

Signature	Title
/s/ Richard L. Armitage *Richard L. Armitage*	Director
/s/ Richard H. Auchinleck *Richard H. Auchinleck*	Director
/s/ James E. Copeland, Jr. *James E. Copeland, Jr.*	Director
/s/ Kenneth M. Duberstein *Kenneth M. Duberstein*	Director
/s/ Ruth R. Harkin *Ruth R. Harkin*	Director
/s/ Harold W. McGraw, III *Harold W. McGraw, III*	Director
/s/ Harald J. Norvik *Harald J. Norvik*	Director
/s/ William K. Reilly *William K. Reilly*	Director
/s/ Bobby S. Shackouls *Bobby S. Shackouls*	Director
/s/ Victoria J. Tschinkel *Victoria J. Tschinkel*	Director
/s/ Kathryn C. Turner *Kathryn C. Turner*	Director
/s/ William E. Wade, Jr.	Director

William E. Wade, Jr.

Table of Contents

CONOCOPHILLIPS
INDEX TO EXHIBITS

Exhibit Number	Description
2.1	Agreement and Plan of Merger, dated as of November 18, 2001, by and among ConocoPhillips Company (formerly named Phillips Petroleum Company), ConocoPhillips (formerly named CorvettePorsche Corp.), P Merger Corp. (formerly named Porsche Merger Corp.), C Merger Corp. (formerly named Corvette Merger Corp.) and ConocoPhillips Holding Company (formerly named Conoco Inc.) (Holding) (incorporated by reference to Annex A to the Joint Proxy Statement/Prospectus included in ConocoPhillips Registration Statement on Form S-4; Registration No. 333-74798).
2.2	Agreement and Plan of Merger, dated as of December 12, 2005, by and among ConocoPhillips, Cello Acquisition Corp. and Burlington Resources Inc. (incorporated by reference to Exhibit 2.1 to the Current Report of ConocoPhillips on Form 8-K filed on December 14, 2005; File No. 001-32395).
3.1	Amended and Restated Certificate of Incorporation (incorporated by reference to Exhibit 3.1 to the Quarterly Report of ConocoPhillips on Form 10-Q for the quarterly period ended June 30, 2008; File No. 001-32395).
3.2	Certificate of Designations of Series A Junior Participating Preferred Stock of ConocoPhillips (incorporated by reference to Exhibit 3.2 to the Current Report of ConocoPhillips on Form 8-K filed on August 30, 2002; File No. 000-49987).
3.3	By-Laws of ConocoPhillips, as amended on December 12, 2008 (incorporated by reference to Exhibit 3.1 to the Current Report of ConocoPhillips on Form 8-K filed on December 12, 2008; File No. 001-32395).
4.1	Rights agreement, dated as of June 30, 2002, between ConocoPhillips and Mellon Investor Services LLC, as rights agent, which includes as Exhibit A the form of Certificate of Designations of Series A Junior Participating Preferred Stock, as Exhibit B the form of Rights Certificate and as Exhibit C the Summary of Rights to Purchase Preferred Stock (incorporated by reference to Exhibit 4.1 to the Current Report of ConocoPhillips on Form 8-K filed on August 30, 2002; File No. 000-49987).
	ConocoPhillips and its subsidiaries are parties to several debt instruments under which the total amount of securities authorized does not exceed 10 percent of the total assets of ConocoPhillips and its subsidiaries on a consolidated basis. Pursuant to paragraph 4(iii)(A) of Item 601(b) of Regulation S-K, ConocoPhillips agrees to furnish a copy of such instruments to the SEC upon request.
10.1	Shareholder Agreement, dated September 29, 2004, by and between LUKOIL and ConocoPhillips (incorporated by reference to Exhibit 99.2 of the Current Report of ConocoPhillips on Form 8-K filed on September 30, 2004; File No. 333-74798).

10.2	1986 Stock Plan of Phillips Petroleum Company (incorporated by reference to Exhibit 10.11 to the Annual Report of ConocoPhillips on Form 10-K for the year ended December 31, 2002; File No. 000-49987).

Table of Contents

Exhibit Number	Description
10.3	1990 Stock Plan of Phillips Petroleum Company (incorporated by reference to Exhibit 10.12 to the Annual Report of ConocoPhillips on Form 10-K for the year ended December 31, 2002; File No. 000-49987).
10.4	Annual Incentive Compensation Plan of Phillips Petroleum Company (incorporated by reference to Exhibit 10.13 to the Annual Report of ConocoPhillips on Form 10-K for the year ended December 31, 2002; File No. 000-49987).
10.5	Incentive Compensation Plan of Phillips Petroleum Company (incorporated by reference to Exhibit 10(g) to the Annual Report of ConocoPhillips Company on Form 10-K for the year ended December 31, 1999; File No. 1-720).
10.6	ConocoPhillips Supplemental Executive Retirement Plan (incorporated by reference to Exhibit 10.7 to the Annual Report of ConocoPhillips on Form 10-K for the year ended December 31, 2005; File No. 001-32395).
10.7	Non-Employee Director Retirement Plan of Phillips Petroleum Company (incorporated by reference to Exhibit 10.18 to the Annual Report of ConocoPhillips on Form 10-K for the year ended December 31, 2002; File No. 000-49987).
10.8	Omnibus Securities Plan of Phillips Petroleum Company (incorporated by reference to Exhibit 10.19 to the Annual Report of ConocoPhillips on Form 10-K for the year ended December 31, 2002; File No. 000-49987).
10.9	Key Employee Missed Credited Service Retirement Plan of ConocoPhillips (incorporated by reference to Exhibit 10.10 to the Annual Report of ConocoPhillips on Form 10-K for the year ended December 31, 2005; File No. 001-32395).
10.10	Phillips Petroleum Company Stock Plan for Non-Employee Directors (incorporated by reference to Exhibit 10.22 to the Annual Report of ConocoPhillips on Form 10-K for the year ended December 31, 2002; File No. 000-49987).
10.11	ConocoPhillips Key Employee Supplemental Retirement Plan.
10.12.1	Defined Contribution Make-Up Plan of ConocoPhillips Title I (incorporated by reference to Exhibit 10.13.1 to the Annual Report of ConocoPhillips on Form 10-K for the year ended December 31, 2005; File No. 001-32395).
10.12.2	Defined Contribution Make-Up Plan of ConocoPhillips Title II.
10.13	2002 Omnibus Securities Plan of Phillips Petroleum Company (incorporated by reference to Exhibit 10.26 to the Annual Report of ConocoPhillips on Form 10-K for the year ended December 31, 2002; File No. 000-49987).
10.14	

1998 Stock and Performance Incentive Plan of ConocoPhillips (incorporated by reference to Exhibit 10.27 to the Annual Report of ConocoPhillips on Form 10-K for the year ended December 31, 2002; File No. 000-49987).

Table of Contents

Exhibit Number	Description
10.15	1998 Key Employee Stock Performance Plan of ConocoPhillips (incorporated by reference to Exhibit 10.28 to the Annual Report of ConocoPhillips on Form 10-K for the year ended December 31, 2002; File No. 000-49987).
10.16	Deferred Compensation Plan for Non-Employee Directors of ConocoPhillips (incorporated by reference to Exhibit 10.17 to the Annual Report of ConocoPhillips on Form 10-K for the year ended December 31, 2005; File No. 001-32395).
10.17	ConocoPhillips Form Indemnity Agreement with Directors (incorporated by reference to Exhibit 10.34 to the Annual Report of ConocoPhillips on Form 10-K for the year ended December 31, 2002; File No. 000-49987).
10.18	Rabbi Trust Agreement dated December 17, 1999 (incorporated by reference to Exhibit 10.11 of Holding s Form 10-K for the year ended December 31, 1999, File No. 001-14521).
10.18.1	Amendment to Rabbi Trust Agreement dated February 25, 2002 (incorporated by reference to Exhibit 10.39.1 to the Annual Report of ConocoPhillips on Form 10-K for the year ended December 31, 2002; File No. 000-49987).
10.19	ConocoPhillips Directors Charitable Gift Program (incorporated by reference to Exhibit 10.40 to the Annual Report of ConocoPhillips on Form 10-K for the year ended December 31, 2003; File No. 000-49987).
10.19.1	First and Second Amendments to the ConocoPhillips Directors Charitable Gift Program (incorporated by reference to Exhibit 10 to the Quarterly Report of ConocoPhillips on Form 10-Q for the quarterly period ended June 30, 2008; File No. 001-32395).
10.20	ConocoPhillips Matching Gift Plan for Directors and Executives (incorporated by reference to Exhibit 10.41 to the Annual Report of ConocoPhillips on Form 10-K for the year ended December 31, 2003; File No. 000-49987).
10.21.1	Key Employee Deferred Compensation Plan of ConocoPhillips Title I (incorporated by reference to Exhibit 10.23.1 to the Annual Report of ConocoPhillips on Form 10-K for the year ended December 31, 2005; File No. 001-32395).
10.21.2	Key Employee Deferred Compensation Plan of ConocoPhillips Title II.
10.22	ConocoPhillips Key Employee Change in Control Severance Plan.
10.23	ConocoPhillips Executive Severance Plan.
10.24	2004 Omnibus Stock and Performance Incentive Plan of ConocoPhillips (incorporated by reference to Appendix C of ConocoPhillips Proxy Statement on Schedule 14A relating to the 2004 Annual Meeting of Shareholders; File No. 000-49987).

10.25	Aircraft Time Sharing Agreement by and between James J. Mulva and ConocoPhillips (incorporated by reference to Exhibit 10 of the Quarterly Report of ConocoPhillips on Form 10-Q for the quarterly period ended June 30, 2007; File No. 001-32395).

Table of Contents

Exhibit Number	Description
10.26	Form of Stock Option Award Agreement under the ConocoPhillips Stock Option and Stock Appreciation Rights Program.
10.27	Form of Restricted Stock Unit Award Agreement under the ConocoPhillips Performance Share Program.
10.28	Omnibus Amendments to certain ConocoPhillips employee benefit plans, adopted December 7, 2007 (incorporated by reference to Exhibit 10.30 to the Annual Report of ConocoPhillips on Form 10-K for the year ended December 31, 2007; File No. 001-32395).
10.29	Letter Agreement between ConocoPhillips and John E. Lowe, dated October 1, 2008 (incorporated by reference to Exhibit 99.1 to the Current Report of ConocoPhillips on Form 8-K filed on October 1, 2008; File No. 001-32395).
10.30	Annex to Nonqualified Deferred Compensation Arangements of ConocoPhillips.
12	Computation of Ratio of Earnings to Fixed Charges.
21	List of Subsidiaries of ConocoPhillips.
23	Consent of Independent Registered Public Accounting Firm.
31.1	Certification of Chief Executive Officer pursuant to Rule 13a-14(a) under the Securities Exchange Act of 1934.
31.2	Certification of Chief Financial Officer pursuant to Rule 13a-14(a) under the Securities Exchange Act of 1934.
32	Certifications pursuant to 18 U.S.C. Section 1350.