CONOCOPHILLIPS
Form 10-K
February 21, 2012
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2011

UNITED STATES

SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

Form 10-K

(Mark One)

[x] ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d)

OF THE SECURITIES EXCHANGE ACT OF 1934

For the fiscal year ended December 31, 2011

For the fiscal year ended **December 31, 2011**

OR

[ ] TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d)

OF THE SECURITIES EXCHANGE ACT OF 1934

For the transition period from to

Commission file number: **001-32395**

ConocoPhillips

(Exact name of registrant as specified in its charter)

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

600 North Dairy Ashford

Houston, TX 77079

(Address of principal executive offices) (Zip Code)

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
6.65% Debentures due July 15, 2018	New York Stock Exchange
7% Debentures due 2029	New York Stock Exchange

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

Indicate by check mark if the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act.

[x] Yes [ ] No

Indicate by check mark if the registrant is not required to file reports pursuant to Section 13 or Section 15(d) of the Act.

[ ] Yes [x] No

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

Indicate by check mark whether the registrant has submitted electronically and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files).

[x] Yes [ ] No

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

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, 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.

Large accelerated filer [x] Accelerated filer [ ] Non-accelerated filer [ ] Smaller reporting company [ ]

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

The aggregate market value of common stock held by non-affiliates of the registrant on June 30, 2011, the last business day of the registrant s most recently completed second fiscal quarter, based on the closing price on that date of $75.19, was $103.2 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 854,854 and 36,219,102 shares, respectively, in determining the aggregate market value.

The registrant had 1,279,692,596 shares of common stock outstanding at January 31, 2012.

Documents incorporated by reference:

Portions of the Proxy Statement for the Annual Meeting of Stockholders to be held on May 9, 2012 (Part III)

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PART I

Unless otherwise indicated, the company, we, our, us and ConocoPhillips are used in this report to refer to the businesses of ConocoPhillips 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 anticipate, estimate, believe, budget, continue, could, intend, may, plan, p seek, should, will, would, expect, objective, projection, forecast, goal, guidance, outlook, effort, target and similar ex forward-looking statements. The company does not undertake to update, revise or correct any 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 73.

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, bitumen, natural gas, liquefied natural gas (LNG) 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 past investment in the ordinary shares of OAO LUKOIL, an international, integrated oil and gas company headquartered in Russia. We completed the divestiture of our entire interest in LUKOIL in the first quarter of 2011.
- **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.

At December 31, 2011, ConocoPhillips employed approximately 29,800 people.

Planned Separation of Downstream Businesses

On July 14, 2011, we announced approval by our Board of Directors to pursue the separation of our refining, marketing and transportation businesses into a stand-alone, publicly traded corporation via a tax-free distribution. The new downstream company, named Phillips 66, will be headquartered in Houston, Texas. In addition to the refining, marketing and transportation businesses, we expect Phillips 66 will also include most of our Midstream segment, our Chemicals segment, as well as our power generation and certain technology operations included in our Emerging Businesses segment, to create an integrated downstream company.

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The separation would be accomplished by the pro rata distribution of one share of Phillips 66 stock for every two shares of ConocoPhillips stock held by ConocoPhillips shareholders on the record date for such distribution.

In October 2011, we requested a private letter ruling from the U.S. Internal Revenue Service, which is expected to confirm the distribution will qualify as a tax-free reorganization for U.S. federal income tax purposes. In addition, we filed the initial Phillips 66 Form 10 registration statement with the U.S. Securities and Exchange Commission (SEC) on November 14, 2011, and an amendment on January 3, 2012.

The separation is subject to market conditions, customary regulatory approvals, the receipt of an affirmative Internal Revenue Service private letter ruling and final Board approval, and is expected to be completed in the second quarter of 2012.

SEGMENT AND GEOGRAPHIC INFORMATION

For operating segment and geographic information, see Note 25 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, 2011, our E&P segment represented 67 percent of ConocoPhillips total assets. This segment primarily explores for, produces, transports and markets crude oil, bitumen, natural gas and natural gas liquids on a worldwide basis. Operations to liquefy natural gas, transport and market the resulting LNG are also included in the E&P segment. At December 31, 2011, our E&P operations were producing in the United States, Norway, the United Kingdom, Canada, Australia, offshore Timor-Leste in the Timor Sea, Indonesia, China, Vietnam, Libya, Nigeria, Algeria, Qatar and Russia.

The E&P segment does not include the financial results or statistics from our prior 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 LUKOIL. However, our share of LUKOIL is included in the Oil and Gas Operations disclosures, as well as in the following net proved reserves table, for periods before we ceased using equity-method accounting for this investment, which occurred at the end of the third quarter of 2010.

The information listed below appears in the Oil and Gas Operations disclosures following the Notes to Consolidated Financial Statements and is incorporated herein by reference:

- Proved worldwide crude oil and natural gas liquids, natural gas, bitumen and synthetic oil reserves.
- Net production of crude oil and natural gas liquids, natural gas, bitumen and synthetic oil.
- Average sales prices of crude oil and natural gas liquids, natural gas, bitumen and synthetic oil.
- Average production costs per barrel of oil equivalent (BOE).
- Net wells completed, wells in progress and productive wells.
- Developed and undeveloped acreage.

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The following table is a summary of the proved reserves information included in the Oil and Gas Operations disclosures following the Notes to Consolidated Financial Statements. Approximately 80 percent of our proved reserves are located in politically stable countries that belong to the Organization for Economic Cooperation and Development. Natural gas reserves are converted to BOE based on a 6:1 ratio: six thousand cubic feet of natural gas converts to one BOE. See Management s Discussion and Analysis of Financial Condition and Results of Operations for a discussion of factors that will enhance the understanding of the table below.

	Millions of Barrels of Oil Equivalent		
Net Proved Reserves at December 31	**2011**	2010	2009
Crude oil and natural gas liquids			
Consolidated operations	**3,287**	3,161	3,194
Equity affiliates	**175**	231	1,710
Total Crude Oil and Natural Gas Liquids	**3,462**	3,392	4,904
Natural gas			
Consolidated operations	**2,933**	3,039	3,161
Equity affiliates	**553**	580	880
Total Natural Gas	**3,486**	3,619	4,041
Bitumen			
Consolidated operations	**530**	455	417
Equity affiliates	**909**	844	716
Total Bitumen	**1,439**	1,299	1,133
Synthetic oil			
Consolidated operations	**-**	-	248
Equity affiliates	**-**	-	-
Total Synthetic Oil	**-**	-	248
Total consolidated operations	**6,750**	6,655	7,020
Total equity affiliates	**1,637**	1,655	3,306
Total company	**8,387**	8,310	10,326
Includes amounts related to LUKOIL investment:	*-*	*-*	*1,967*

In 2011, E&P s worldwide production, including its share of equity affiliates, averaged 1,619,000 barrels of oil equivalent per day (BOED), compared with 1,752,000 BOED in 2010. During 2011, 653,000 BOED were produced in the United States, a 5 percent decrease from 686,000 BOED in 2010. Production from our international E&P operations averaged 966,000 BOED in 2011, a 9 percent decrease from 1,066,000 BOED in 2010. Worldwide production decreased primarily due to suspended operations in Libya and Bohai Bay, China, asset dispositions and unplanned downtime. Normal field decline was largely offset by new production.

E&P s worldwide annual average crude oil and natural gas liquids sales price increased 34 percent, from $72.77 per barrel in 2010 to $97.22 per barrel in 2011. Worldwide bitumen prices increased 18 percent, from $53.06 per barrel in 2010 to $62.56 per barrel in 2011. E&P s average annual worldwide natural gas sales price increased 7 percent, from $4.98 per thousand cubic feet in 2010 to $5.34 per thousand cubic feet in 2011.

E&P UNITED STATES

In 2011, U.S. E&P operations contributed 45 percent of E&P s worldwide liquids production and 36 percent of natural gas production.

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Alaska

	Interest	Operator	2011 Liquids MBD[1]	Natural Gas MMCFD[2]	Total MBOED[3]
Average Daily Net Production					
Greater Prudhoe Area	36.1%	BP	106	6	107
Greater Kuparuk Area	52.2-55.4	COP	58	-	58
Western North Slope	78.0	COP	51	1	51
Cook Inlet Area	33.3-100	COP	-	54	9
Total Alaska			215	61	225

(1)Thousands of barrels per day.

(2)Millions of cubic feet per day.

(3)Thousands of barrels of oil equivalent per day.

Greater Prudhoe Area

The Greater Prudhoe Area includes 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 which processes natural gas for reinjection into the reservoir. Prudhoe Bay s satellites are Aurora, Borealis, Polaris, Midnight Sun and Orion, while the Point McIntyre, Niakuk, Raven and Lisburne fields are part of the Greater Point McIntyre Area.

Greater Kuparuk Area

We operate the Greater Kuparuk Area, which is made up of the Kuparuk Field and four satellite fields: Tarn, Tabasco, Meltwater and West Sak. Kuparuk is located 40 miles west of Prudhoe Bay on Alaska s North Slope. Field installations include three central production facilities that separate oil, natural gas and water, as well as a separate seawater treatment plant. The natural gas is either used for fuel or compressed for reinjection.

Western North Slope

On the Western North Slope, we operate the Colville River Unit, which includes the Alpine Field and three satellite fields: Nanuq, Fiord and Qannik. Alpine is located 34 miles west of Kuparuk. In December 2011, the U.S. Army Corps of Engineers granted us a permit required to build a gravel road, bridge and pipeline crossing over the Nigliq channel of the Colville River for development of a satellite field west of Alpine in the National Petroleum Reserve Alaska (NPRA), the Alpine West CD5 Project. We plan to incorporate the terms of the permit into our project plan as we progress project sanctioning of CD5 in 2012. Initial production is anticipated toward the end of 2015.

Cook Inlet Area

We operate the North Cook Inlet Unit, the Beluga River Unit, and the Kenai LNG Plant in the Cook Inlet Area. We have a 100 percent interest in the North Cook Inlet Unit, while we own 33.3 percent of the Beluga River Unit. Our share of production is used to supply feedstock and fuel to the Kenai LNG Plant and is also sold to local utilities.

In October 2011, we acquired an additional 30 percent interest in the Kenai LNG Plant, bringing our ownership interest to 100 percent. The Kenai LNG Plant had historically supplied LNG to utility companies in Japan. Due to market conditions, the Kenai Plant was scheduled to be mothballed in the second quarter of 2011; however, we delayed the shutdown in order to ship additional cargoes to Asia, due to energy shortages caused by the earthquake and tsunami in Japan. In November 2011, we idled the plant for future use. We subsequently secured additional third-party gas supplies, and as a result, expect to resume limited LNG exports in the second half of 2012.

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Exploration

In the February 2008 Outer Continental Shelf (OCS) Lease Sale 193, we successfully bid and were awarded 10-year-primary-term leases on 98 blocks in the Chukchi Sea. We plan to drill an exploration well on our Chukchi Sea leasehold in 2014, subject to the outcome of pending litigation challenging Lease Sale 193 and the receipt of required regulatory permits.

In January 2010, we exchanged a 25 percent working interest in 50 of our leases in the Chukchi Sea for cash consideration and additional working interests in the deepwater Gulf of Mexico. In late 2010, we entered into an agreement to farm-down an additional 10 percent of our working interest in the same Chukchi Sea leases, and that agreement received regulatory approval in July 2011.

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.

In 2008, ConocoPhillips and BP plc formed a limited liability company to progress the pipeline project named Denali The Alaska Gas Pipeline. The project was intended to move natural gas from Alaska s North Slope to North American markets. In May 2011, the project was canceled as a result of insufficient customer transportation commitments to the project.

U.S. Lower 48

				2011 Natural	
			Liquids	Gas	Total
	Interest	Operator	MBD	MMCFD	MBOED
Average Daily Net Production					
Eagle Ford	Various%	Various	22	39	29
Williston	Various	Various	15	12	17
Fort Worth	Various	Various	6	47	13
Permian	Various	Various	29	111	48
San Juan	Various	Various	49	773	179
Lobo	Various	COP	5	138	28
Panhandles	Various	Various	2	76	15
Wind River	Various	Various	-	88	15
Bossier	Various	Various	-	67	11
Anadarko	Various	Various	3	59	12
Other onshore	Various	Various	21	129	42
Gulf of Mexico	Various	Various	16	17	19
Total U.S. Lower 48			168	1,556	428

Onshore

Our 2011 onshore production principally consisted of natural gas and associated liquids production, with the majority of production located in the San Juan Basin, Permian Basin, Lobo Trend, Eagle Ford, Williston Basin, panhandles of Texas and Oklahoma, Fort Worth Basin, Anadarko Basin and Bossier Trend. We also have operations in the Wind River Basin, East Texas, Rockies and northern and southern Louisiana. Onshore activities in 2011 were centered mostly on continued optimization and development of existing assets, with particular focus on areas with higher liquids production.

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Shale Plays

Exploration and development continues in our shale positions in Eagle Ford, Bakken and Barnett. In the Eagle Ford, we drilled approximately 160 exploration and development wells in 2011 and plan to drill approximately 200 wells in 2012. With subsequent investments, we expect to achieve peak production in 2017 and long-term average production of 140,000 BOED. During 2011, we acquired approximately 240,000 additional acres in various resource plays across the Lower 48, which included the Avalon, Wolfcamp and Niobrara areas, further expanding our significant acreage position in Lower 48 shale plays.

San Juan

The San Juan Basin, located in northwestern New Mexico and southwestern Colorado, includes the majority of our U.S. coalbed methane (CBM) production. We continue to pursue development opportunities in three conventional formations in the San Juan Basin.

Gulf of Mexico

At year-end 2011, our portfolio of producing properties in the Gulf of Mexico 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.

Exploration

In the Gulf of Mexico, we have a 45 percent interest in the Coronado well, which was spud in October 2011. A decision to cease drilling the well was made prior to reaching the targeted depth, and the well was expensed as a dry hole. We are in the planning process to appraise the results of Tiber and Shenandoah, which were discovered in 2009. Additionally, we were the successful bidder on 75 blocks in the Paleogene play in OCS Lease Sale 218 in December 2011. We expect these blocks will be awarded in 2012.

Offshore south Louisiana, we drilled the Shalimar exploration well. The well did not reach its target depth due to technical drilling issues and was expensed as a dry hole.

Onshore, we actively pursued the appraisal of our existing unconventional resource plays, including the Eagle Ford in South Texas, the Bakken in the Williston Basin, and the Barnett in the Fort Worth Basin. We have seen encouraging results in these liquids-rich plays and plan to continue appraisal and development in 2012.

Transportation

We have a 25 percent interest in the Rockies Express Pipeline (REX). The REX natural gas pipeline runs 1,679 miles from Cheyenne, Colorado, to Clarington, Ohio, and has a natural gas transmission capacity of 1.8 billion cubic feet per day. Numerous compression facilities support the pipeline system. The REX pipeline is designed to enable natural gas producers in the Rocky Mountains region to deliver natural gas supplies to the Midwest and eastern regions of the United States. Upon the completion of the separation of the downstream businesses, we expect REX will be included in the new downstream company, Phillips 66.

E&P EUROPE

In 2011, E&P operations in Europe contributed 20 percent of E&P s worldwide liquids production and 14 percent of natural gas production. Our European assets are principally located in the Norwegian and U.K. sectors of the North Sea.

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Norway

			2011		
			Liquids	Natural Gas	Total
	Interest	Operator	MBD	MMCFD	MBOED
Average Daily Net Production					
Greater Ekofisk Area	35.1%	COP	73	66	84
Alvheim	20.0	Marathon	14	11	16
Heidrun	24.1	Statoil	10	11	12
Statfjord Area	6.0-12.1	Statoil	7	13	9
Other	Various	Various	16	62	26
Total Norway			120	163	147

The Greater Ekofisk Area, located approximately 200 miles offshore Stavanger, Norway in the North Sea, is comprised of four producing fields: Ekofisk, Eldfisk, Embla and Tor. Ekofisk crude oil is exported to Teesside, England, and the natural gas is exported to Emden, Germany. Our Ekofisk South and Eldfisk II projects continue to progress, with production from both of these projects expected in 2013 and 2014, respectively.

The Alvheim development consists of a floating production, storage and offloading (FPSO) vessel and subsea installations. Produced crude oil is exported via shuttle tankers, and natural gas is transported to the United Kingdom via a pipeline to the Beryl-Sage system.

The Heidrun Field is located in the Norwegian Sea. Produced crude oil is transported to Mongstad in Norway and Tetney in the United Kingdom by double-hulled shuttle tankers. Part of the natural gas is transported and sold to buyers in Europe, while the remainder is used as feedstock in a methanol plant in Norway, in which we own an 18.3 percent interest.

The Statfjord Field straddles the boundary between the United Kingdom and Norway. In January 2012, we entered into an agreement to sell our interests in the Statfjord Field and associated satellites. The transaction is expected to close in the second quarter of 2012.

We also have varying ownership interests in five other producing fields in the Norwegian sector of the North Sea and in the Norwegian Sea.

Exploration

During 2011, we drilled one exploration well, Peking Duck (7/11-12S), including the Agn sidetrack well (7/11-12A). The wells were non-commercial gas discoveries and were expensed as dry holes. In addition, we participated in two partner-operated wells, Caterpillar (PL340BS) in the Alvheim Area and Arran (PL309) in the Oseberg Area. The Caterpillar discovery is currently being evaluated. Arran was a dry hole and has been plugged and abandoned.

We were awarded three new licenses in the Norwegian 21st Licensing Round: PL603, a 25 percent working interest in the Norwegian Sea; PL605, a 50 percent operating interest in the Barents Sea; and PL615, a 25 percent working interest in the Barents Sea. We acquired 3D seismic over PL605.

Transportation

We own a 35.1 percent interest in the Norpipe Oil Pipeline System, a 220-mile pipeline which carries crude oil from Ekofisk to a terminal and natural gas processing facility in Teesside, England. In addition, we own a 1.9 percent interest in Norwegian Continental Shelf Gas Transportation (Gassled), which owns most of the Norwegian gas transportation infrastructure.

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United Kingdom

			2011		
			Liquids	Natural Gas	Total
	Interest	Operator	MBD	MMCFD	MBOED
Average Daily Net Production					
Britannia	58.7%	Britannia Operator Ltd.	5	136	28
Britannia Satellites	75.0-83.5	COP	20	57	30
J-Block	32.5-36.5	COP	11	74	23
Southern North Sea	Various	Various	-	127	21
East Irish Sea	100	HRL	-	62	10
Other	Various	Various	19	7	20
Total United Kingdom			55	463	132

In addition to our interest in the Britannia natural gas and condensate field, we own 50 percent of Britannia Operator Limited, the operator of the field. Condensate is delivered through the Forties Pipeline to an oil stabilization and processing plant near the Grangemouth Refinery in Scotland, while natural gas is transported through Britannia s line to St. Fergus, Scotland. The Britannia satellite fields, Callanish and Brodgar, produce via subsea manifolds and pipelines linked to the Britannia platform.

J-Block is comprised of the Judy/Joanne, Jade and Jasmine fields, located in the U.K. central North Sea. In 2010, we received government approval for the development of the Jasmine Field, which is expected to achieve average net peak production of 34,000 BOED by 2013.

We have various ownership interests in 18 producing gas fields in the Rotliegendes and Carboniferous areas of the Southern North Sea. Our interests in the East Irish Sea include the Millom, Dalton and Calder fields, which are operated on our behalf by a third party.

We own a 24 percent interest in the Clair Field, located in the Atlantic Margin. The Clair Ridge Project received government approval in October 2011, and we anticipate initial production in 2016.

In December 2011, we entered into an agreement to sell our interests in the MacCulloch, Alba and Nicol fields. The sales of these interests are expected to close in the first half of 2012.

Exploration

During 2011, we participated in two partner-operated exploration wells. Well 206/12a-3 in the Clair South West Area, West of Shetlands, was an oil discovery and has been suspended in order to evaluate development options for the area. The Cameron well (44/19a-7a) in the Southern North Sea was a small gas discovery and is currently being evaluated for commerciality.

Transportation

We have a 10 percent interest in the Interconnector Pipeline, which links the United Kingdom and Belgium and facilitates the marketing throughout Europe of natural gas produced in the United Kingdom. We have export capability to ship up to 220 million cubic feet of natural gas per day to markets in continental Europe via the Interconnector, and our reverse-flow rights provide 85 million cubic feet per day of 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 ownership interests, respectively. We also have a 100 percent ownership interest in the Rivers Gas Terminal, operated by a third party, in the United Kingdom.

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Poland

Exploration

We are participating in a shale gas venture in Poland, which provides us with the option to earn a 70 percent operating interest in six exploration licenses in the Baltic Basin. We participated in two wells in 2011.

E&P CANADA

In 2011, E&P operations in Canada contributed 12 percent of E&P s worldwide liquids production and 21 percent of E&P s worldwide natural gas production.

			2011			
	Interest	Operator	Liquids MBD	Natural Gas MMCFD	Bitumen MBD	Total MBOED
Average Daily Net Production						
Western Canada	Various%	Various	38	928	-	193
Surmont	50.0	COP	-	-	10	10
Foster Creek	50.0	Cenovus	-	-	46	46
Christina Lake	50.0	Cenovus	-	-	11	11
Total Canada			38	928	67	260

Western Canada

Our operations in western Canada are primarily comprised of three core development areas: Deep Basin, Kaybob and O Chiese, which extend from central Alberta to northeastern British Columbia. We operate or have ownership interests in approximately 80 natural gas processing plants in the region, and, as of December 31, 2011, held leasehold rights in 6 million net acres in western Canada.

Oil Sands

We hold approximately 1 million net acres of land in the Athabasca Region of northeastern Alberta. Our bitumen resources in Canada are produced via an enhanced thermal oil recovery method called steam-assisted gravity drainage (SAGD), whereby steam is injected into the reservoir, effectively liquefying the heavy bitumen, which is recovered and pumped to the surface for further processing.

Surmont

The Surmont oil sands lease is located approximately 35 miles south of Fort McMurray, Alberta. Surmont Phase II construction began in 2010, with production startup targeted for 2015. Surmont s net production is expected to increase to 50,000 barrels per day by 2016.

FCCL

We have two 50/50 North American heavy oil business ventures with Cenovus Energy Inc.: FCCL Partnership, a Canadian upstream general partnership, and WRB Refining LP, a U.S. downstream limited partnership. FCCL s assets, operated by Cenovus, include the Foster Creek, Christina Lake and Narrows Lake SAGD bitumen projects.

Construction continued in 2011 on Foster Creek Phase F, the first of three additional approved expansion phases. Upon completion of Foster Creek Phases F, G and H, net peak production is anticipated to increase by 42,500 barrels per day beginning in 2014. At Christina Lake, first production for Phase C occurred in the third quarter of 2011. Construction of Christina Lake Phase D continued through 2011, with initial production expected in late 2012. Once phases C and D are both fully operational, net peak production at Christina Lake is estimated to be 47,000 barrels per day. Christina Lake Phases E, F and G received regulatory approval in the second quarter of 2011, and construction on Phase E commenced in the third quarter of 2011.

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Narrows Lake is an emerging opportunity within the FCCL Partnership. A regulatory application for the development of Narrows Lake was submitted in June 2010, and we anticipate receiving a response in the second quarter of 2012. Initial production is anticipated in 2017.

For information on WRB, see the Refining and Marketing (R&M) section.

Parsons Lake/Mackenzie Gas Project

We are involved 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 natural gas field, one of the primary fields in the Mackenzie Delta, which would anchor the pipeline development. In March 2011, the project received regulatory approval from the National Energy Board of Canada. However, due to a continued decline in market conditions and lack of resolution with the Canadian government on fiscal terms, we are currently evaluating multiple options regarding the scope and timing of this project. Should the project not proceed, we would need to assess for impairment the carrying value of the undeveloped leasehold and capitalized project development costs, which totaled $662 million at December 31, 2011, including capitalized interest.

Amauligak

We have a 53.8 percent operating interest in Amauligak, which lies approximately 31 miles offshore in shallow water in the Beaufort Sea. A range of development options are being evaluated.

Exploration

We hold exploration acreage in four areas of Canada: offshore eastern Canada, onshore western Canada, the Mackenzie Delta/Beaufort Sea Region and the Arctic Islands. During 2011, we conducted pilot drilling programs in the Muskwa (Horn River Basin) and Duvernay (West Shale Basin) unconventional resource plays, and we acquired approximately 260,000 acres of exploration leasehold in the Canol Shale, Duvernay Shale and other plays.

E&P SOUTH AMERICA

Venezuela

In 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. As a result, Venezuela s national oil company, Petróleos de Venezuela S.A. (PDVSA), or its affiliates, directly assumed control over ConocoPhillips interests in the Petrozuata and Hamaca heavy oil ventures and the offshore Corocoro development project. In response to this expropriation, we filed a request for international arbitration on November 2, 2007, with the World Bank s International Centre for Settlement of Investment Disputes (ICSID). An arbitration hearing was held before an ICSID tribunal during the summer of 2010, and we are currently awaiting an interim decision on key legal and factual issues. A separate arbitration hearing was held in January 2012 before the International Chamber of Commerce on ConocoPhillips separate claims against PDVSA for certain breaches of their Association Agreements prior to the expropriation.

Ecuador

In 2008, Burlington Resources, Inc., a wholly owned subsidiary of ConocoPhillips, initiated arbitration before ICSID against The Republic of Ecuador, as a result of the newly enacted Windfall Profits Tax Law and government-mandated renegotiation of our production sharing contracts. Despite a restraining order issued by ICSID, Ecuador confiscated the crude oil production of Burlington and its co-venturer and sold the illegally seized crude oil. In 2009, Ecuador took over operations in Blocks 7 and 21, fully expropriating our assets. In June 2010, the ICSID tribunal concluded it has jurisdiction to hear the expropriation claim. An arbitration hearing on case merits occurred in March 2011. On September 30, 2011, Ecuador filed a supplemental counterclaim asserting environmental damages, which we believe will not be material. The arbitration process is ongoing.

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Peru

Exploration

We own a 45 percent operating interest in Blocks 123 and 129, covering nearly 1.6 million net acres. During 2011, we completed an initial 2-D seismic program on Blocks 123 and 129 and began to further delineate the play with an infill 2-D seismic program. In April 2011, we entered into an agreement to sell our entire 35 percent interest in Block 39, subject to government approval. Block 124 was relinquished in May 2011.

E&P ASIA PACIFIC/MIDDLE EAST

In 2011, E&P operations in the Asia Pacific/Middle East Region contributed 15 percent of E&P s worldwide liquids production and 26 percent of natural gas production.

Australia and Timor Sea

				2011	
				Natural	
			Liquids	Gas	Total
	Interest	Operator	MBD	MMCFD	MBOED
Average Daily Net Production					
Australia Pacific LNG	42.5%	Origin Energy	-	122	20
Bayu-Undan	56.9	COP	30	199	63
Athena/Perseus	50.0	ExxonMobil	-	35	6
Total Australia and Timor Sea			30	356	89

Australia Pacific LNG

Australia Pacific LNG (APLNG), our joint venture with Origin Energy and China Petrochemical Corporation (Sinopec), is focused on producing CBM from the Bowen and Surat basins in Queensland, Australia. Origin operates APLNG s production and pipeline system, and we will operate the LNG facility. Natural gas is currently sold to domestic customers, while progress continues on the development of an LNG processing and export sales business. Once established, this will enhance our LNG position and serve as an additional LNG hub supplying Asia Pacific markets. Two initial 4.5-million-tonnes-per-year LNG trains are anticipated, with over 10,000 net wells ultimately envisioned to supply both the domestic gas market and the LNG development. The additional wells will be supported by expanded gas gathering systems, centralized gas processing and compression stations, and water treatment facilities, in addition to a new export pipeline from the gas fields to the LNG facilities.

The project received environmental approval from the Australian federal government in February 2011, and a final investment decision on the initial LNG train and common facilities was approved in July 2011. The project s first LNG exports are expected to begin in 2015.

In April 2011, APLNG and Sinopec signed definitive agreements for APLNG to supply up to 4.3 million tonnes of LNG per year for 20 years. The agreements also specified terms under which Sinopec subscribed for a 15 percent equity interest in APLNG, with both our ownership interest and Origin Energy s ownership interest diluting from 50 percent to 42.5 percent. The Subscription Agreement was completed in August 2011.

In November 2011, APLNG signed a binding Heads of Agreement with Japan-based Kansai Electric Power Co. Inc., for the sale of approximately 1 million tonnes of LNG per year for 20 years. Under the terms of the agreement, Kansai Electric will be supplied LNG beginning in mid-2016. The agreement is subject to a final investment decision on the second LNG train, which is expected in the first half of

2012.

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In January 2012, APLNG and Sinopec signed an amendment to their existing LNG sales agreement for the sale and purchase of an additional 3.3 million tonnes of LNG per year through 2035, subject to a final investment decision on the second LNG train. This agreement, in combination with the Kansai Electric agreement, finalizes the marketing of the second train. In conjunction with the LNG sale, the parties have also agreed for Sinopec to subscribe for additional shares in APLNG, which would raise its equity interest from 15 percent to 25 percent. As a result, both our ownership interest and Origin Energy s ownership interest would dilute from 42.5 percent to 37.5 percent. These agreements are subject to customary government approvals.

For additional information, see Note 6 Investments, Loans and Long-Term Receivables, in the Notes to Consolidated Financial Statements.

Bayu-Undan

The Bayu-Undan gas condensate field is located in the Timor Sea joint petroleum development area between Timor-Leste and Australia. We also operate and own a 56.9 percent interest in the associated Darwin LNG facility, located at Wickham Point, Darwin. Produced natural gas is used to supply the Darwin LNG Plant. In 2011, we sold 153 billion gross cubic feet of LNG to utility customers in Japan.

Athena/Perseus

The Athena production license (WA-17-L) is located offshore Western Australia and contains part of the Perseus Field which straddles the boundary with WA-1-L, an adjoining license area. Natural gas is produced from these licenses.

Greater Sunrise

We have a 30 percent interest in the Greater Sunrise gas and condensate field located in the Timor Sea. Although the governments of Australia and Timor-Leste have reached an agreement concerning sharing of revenues from the anticipated development of Greater Sunrise, key challenges must be resolved before significant funding commitments can be made. These include gaining both governments approval of the development concept selected by the co-venturers.

Exploration

We operate three permits located in the Browse Basin, offshore northwest Australia. We own a 60 percent interest in two of the permits, WA-315-P and WA-398-P. In February 2012, we received regulatory approval to reduce our interest in the third permit, WA-314-P, from 60 percent to 10 percent. The first phase of drilling in 2009/2010 resulted in discoveries in WA-315-P and WA-398-P. In 2011, we completed the analysis of the 3-D seismic survey acquired during the 2009/2010 drilling campaign. The Phase II drilling campaign will commence in the first quarter of 2012 and will comprise a five- to eight-well program.

During 2011, we executed an option agreement to earn up to a 75 percent working interest in the Goldwyer Shale Project located in the Canning Basin of Western Australia. Drilling is expected to commence in 2012. Upon completion of the initial drilling program, we will have the right to assume operatorship of the Goldwyer Shale Project. The agreement is awaiting regulatory approvals.

In the Bonaparte Basin, offshore northern Australia, we operate and own a 60 percent interest in two permits, NT/P69 and NT/P61. During 2011, we reprocessed the seismic data over the Caldita structure in NT/P61, which will allow us to fully evaluate the remaining exploration potential of the permit.

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Indonesia

	Interest	Operator	Liquids MBD	2011 Natural Gas MMCFD	Total MBOED
Average Daily Net Production					
South Natuna Sea Block B	40.0%	COP	8	117	28
South Sumatra	45.0-54.0	COP	3	333	58
Total Indonesia			11	450	86

We operate six production sharing contracts (PSCs) in Indonesia. Three of the blocks are located offshore: South Natuna Sea Block B, Kuma and Arafura Sea. The three onshore PSCs consist of the Corridor Block, South Jambi B , both in South Sumatra, and Warim in Papua. Our producing assets are primarily concentrated in two core areas: South Natuna Sea and onshore South Sumatra.

South Natuna Sea Block B

The offshore South Natuna Sea Block B PSC has two producing oil fields and 16 natural gas fields in various stages of development. Natural gas production is sold under international sales agreements to Malaysia and Singapore.

South Sumatra

The Corridor PSC consists of six oil fields and six natural gas fields in various stages of development. Natural gas is supplied from the Grissik and Suban gas processing plants to the Duri steamflood in central Sumatra and to markets in Singapore, Batam and West Java. Unitization of the Suban natural gas field was finalized in 2011, and as a result, 10 percent of the field s proved reserves are now attributable to an adjacent PSC. The South Jambi B PSC includes three gas fields which are in various stages of development.

Exploration

We operate two offshore exploration PSCs, Kuma and Arafura Sea, with ownership interests of 60 percent and 51 percent, respectively. During 2011, we drilled the Kaluku well in the Kuma PSC and the Mutiara Putih well in the Arafura Sea PSC. Both were expensed as dry holes. A third PSC, Amborip VI, was relinquished in 2011. We also own and operate an 80 percent interest in the Warim onshore exploration PSC in Papua.

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.

China

	Interest	Operator	Liquids MBD	2011 Natural Gas MMCFD	Total MBOED
Average Daily Net Production					

Peng Lai	49.0%	COP	42	-	42
Panyu	24.5	CNOOC	10	-	10
Total China			52	-	52

The Peng Lai 19-3, 19-9 and 25-6 fields are located in Bohai Bay Block 11/05. Production from the Phase I development of the PL 19-3 Field began in 2002. The Phase II development includes six drilling and production platforms and an FPSO vessel used to accommodate production from all the fields.

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On July 13, 2011, the State Oceanic Administration (SOA) in the People s Republic of China instructed us to suspend production from the Peng Lai 19-3 Field Platforms B and C, as a result of two separate seepage incidents which occurred near the platforms. On September 2, 2011, the SOA ordered us to halt operations at the Peng Lai 19-3 Field, pending additional cleanup efforts and reservoir depressurization activities to ensure any residual seepage had stopped. The incidents resulted in a total release of approximately 700 barrels of oil into Bohai Bay and approximately 2,600 barrels of mineral oil-based drilling mud onto the seafloor. The mineral oil-based drilling mud was recovered and cleaned up from the seafloor. The sources of the seeps have been sealed and containment devices deployed as a preventative measure to capture any residue.

The SOA also required implementation of preventative measures to avoid recurrence, in addition to the filing of an updated environmental impact assessment and development plan for approval. A revised development plan was submitted to China s National Development and Reform Commission in November 2011 and is currently under review. A revised environmental impact assessment was submitted to the SOA in February 2012.

The approved depressurization plan, combined with limited development and field optimization, reduced 2011 average daily net production from the field by 14,000 barrels of oil per day, compared to 2010 production levels. Future impacts on our business are not known at this time.

In January 2012, we and the China National Offshore Oil Corp. (CNOOC) announced an agreement with China s Ministry of Agriculture to resolve fishery-related issues in connection with the seepage incidents. Under this agreement, approximately $160 million will be paid as compensation to settle private claims of potentially affected fishermen in relevant Bohai Bay communities, and public claims for alleged fishery damage. We hold a 49 percent ownership interest in the Peng Lai fields. The agreement fulfills the objectives of the compensation fund we announced in September 2011. As part of this agreement, we have also designated approximately $16 million of our previously announced environmental fund to be used to improve fishery resources and for related projects.

The Panyu development, also located in the South China Sea, is comprised of three oil fields: Panyu 4-2, Panyu 5-1 and Panyu 11-6. An expansion of the scope and capacity of the existing Panyu 4-2 and Panyu 5-1 fields is being undertaken, with the addition of two production platforms targeted for completion in 2013.

Vietnam

				2011	
	Interest	Operator	Liquids MBD	Natural Gas MMCFD	Total MBOED
Average Daily Net Production					
Su Tu Den and Su Tu Vang	23.3%	Cuu Long Joint Operating Company	13	5	14
Rang Dong	36.0	Japan Vietnam Petroleum Co.	5	6	6
Total Vietnam			18	11	20

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 and one gas pipeline transportation system.

Our activities in Block 15-1 are focused around three producing fields: Su Tu Den, Su Tu Den Northeast and Su Tu Vang; and two fields in development: Su Tu Trang and Su Tu Nau. Su Tu Den crude oil is processed and stored in a 1-million-barrel FPSO vessel.

The Rang Dong Field is located in Block 15-2. Rang Dong crude oil is stored in a floating storage and offloading vessel.

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In February 2012, we entered into an agreement to sell our entire Vietnam business. The transaction is expected to close in the first half of 2012.

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

An appraisal well, SD-9Pst, was drilled and completed as a producer in the Su Tu Den Field. Early production data is currently being evaluated.

Malaysia

We own interests in three deepwater PSCs located off the eastern Malaysian state of Sabah: Block G, Block J and the Kebabangan Cluster. We have a 35 percent interest in Block G, 40 percent in Block J and 30 percent in the Kebabangan Cluster. Development of the Gumusut deepwater oil discovery in Block J continues and includes the installation of a semi-submersible oil production platform. First production from Gumusut is anticipated in 2012, with estimated net peak production of 32,000 barrels of liquids per day occurring in 2014. The development of the Kebabangan Gas Field (KBB) started in 2011, with first production anticipated in late 2014. Estimated net annual peak production from KBB is 29,000 BOED occurring in 2015.

Bangladesh

Exploration

In 2009, we were formally awarded two deepwater blocks in the Bay of Bengal, offshore Bangladesh. We received government approval of the PSC terms in June 2011 and hold 100 percent interests in Blocks 10 and 11. Seismic acquisition activities are expected to commence in early 2012.

Brunei

Exploration

In 2011, we acquired a 6.25 percent working interest in Block CA-2. We drilled two exploration wells in 2011, which were expensed as dry holes. Exploration activities will continue in 2012.

Qatar

				2011 Natural	
			Liquids	Gas	Total
	Interest	Operator	MBD	MMCFD	MBOED
Average Daily Net Production					
Qatargas 3	30.0%	Qatargas Operating Co.	23	370	85
Total Qatar			23	370	85

Qatargas 3 (QG3) is an integrated project jointly owned by Qatar Petroleum (68.5 percent), ConocoPhillips (30 percent) and Mitsui & Co., Ltd. (1.5 percent). The project comprises upstream natural gas production facilities to produce approximately 1.4 billion gross cubic feet per day of natural gas from Qatar s North Field over a 25 year life. The project also includes a 7.8-million-gross-tonnes-per-year LNG facility, from which LNG is shipped in leased LNG carriers destined for sale in the United States and other markets. First production was achieved in October 2010, and we achieved peak production during 2011.

QG3 executed the development of the onshore and offshore assets as a single integrated project with Qatargas 4 (QG4), a joint venture between Qatar Petroleum and Royal Dutch Shell plc. This included 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 QG3 and QG4 joint ventures. Production from the LNG trains and associated facilities are combined and shared.

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We have a 12.4 percent ownership interest in the Golden Pass LNG Terminal and affiliated Golden Pass Pipeline. It is located adjacent to the Sabine-Neches Industrial Ship Channel northwest of Sabine Pass, Texas. The terminal became commercially operational in May 2011. We hold terminal and pipeline capacity for the receipt, storage and regasification of the LNG purchased from QG3 and the transportation of regasified LNG to interconnect with major interstate natural gas pipelines. Market conditions currently favor the flow of LNG to European and Asian markets; therefore, our near-to-mid-term utilization of the terminal is expected to be limited.

E&P AFRICA

During 2011, E&P operations in Africa contributed 5 percent of E&P s worldwide liquids production and 3 percent of natural gas production.

Nigeria

	Interest	Operator	Liquids MBD	2011 Natural Gas MMCFD	Total MBOED
Average Daily Net Production					
OMLs 60, 61, 62, 63	20.0%	Eni	19	157	45
Total Nigeria			19	157	45

We have an interest in four onshore Oil Mining Leases (OMLs). Natural gas is sourced from our proved reserves in the OMLs and provides fuel for a 480-megawatt gas-fired power plant in Kwale, Nigeria. We have a 20 percent interest in this power plant, which supplies electricity to Nigeria s national electricity supplier. In 2011, the plant consumed 12 million net cubic feet per day of natural gas.

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

Exploration

The Uge North exploration well in OPL 214 was spud in December 2011 as a step-out to the 2005 Uge Field discovery. It is the first of two remaining commitment wells.

Libya

	Interest	Operator	Liquids MBD	2011 Natural Gas MMCFD	Total MBOED
Average Daily Net Production					
Waha Concession	16.3%	Waha Oil Co.	8	1	8
Total Libya			8	1	8

The Waha Concession is made up of multiple concessions and encompasses nearly 13 million gross acres in the Sirte Basin. Our production operations in Libya and related oil exports were temporarily suspended in 2011 during Libya s period of civil unrest. Production restarted in late November 2011, and by year-end 2011, net production was approximately 15,000 BOED.

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Algeria

	Interest	Operator	2011 Liquids MBD	Natural Gas MMCFD	Total MBOED
Average Daily Net Production					
Menzel Lejmat North	65.0%	COP	9	-	9
Ourhoud	3.7	L Organization Ourhoud	4	-	4
Total Algeria			13	-	13

Our activities in Algeria are centered around three fields in Block 405a: the Menzel Lejmat North Field (MLN), the Ourhoud Field and the EMK Field. Crude oil production from MLN and Ourhoud is transported to northern Algerian ports where it is lifted to tankers and marketed primarily to refineries in North America and Europe. The El Merk Project was sanctioned in 2009 to develop the EMK Field, in which we own a 16.9 percent interest. Engineering, procurement and construction is ongoing.

Angola

Exploration

In December 2011, we signed two PSCs with Angola s national oil company for a 42.86 percent operating interest in two ultra deepwater blocks, Blocks 36 and 37, in Angola s subsalt play trend. These agreements became effective in January 2012, and we anticipate commencing acquisition of seismic data in early 2012.

E&P RUSSIA

During 2011, E&P operations in Russia contributed 3 percent of E&P s worldwide liquids production.

	Interest	Operator	2011 Liquids MBD	Natural Gas MMCFD	Total MBOED
Average Daily Net Production					
Naryanmarneftegaz (NMNG)	30.0%	OOO NMNG	23	-	23
Polar Lights	50.0	Polar Lights Co.	6	-	6
Total Russia			29	-	29

NMNG

NMNG is a joint venture we entered into with LUKOIL to develop oil and natural gas resources in the northern part of Russia s Timan-Pechora Province. Yuzhno Khylchuyu (YK), NMNG s anchor field, achieved first production in June 2008. The joint venture currently holds seven licenses and is producing from five fields. Production is transported via pipeline to LUKOIL s terminal at Varandey Bay on the Barents Sea and then shipped via tanker to international markets.

Polar Lights

Polar Lights Company is an entity which was established to develop the Ardalin Field in the Timan-Pechora Basin in northern Russia.

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E&P CASPIAN

In the Caspian Sea, we have an 8.4 percent 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, processing facilities, living quarters and pipelines to carry production onshore. In addition to the Kashagan Field, the NCSPSA includes the satellite fields of Aktote, Kairan and Kalamkas. The initial production phase of the contract lasts until 2041. First production is expected in 2013.

Transportation

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

Exploration

We have a 24.5 percent interest in the N Block, located offshore Kazakhstan. In the fourth quarter of 2010, drilling operations were completed on the Rak More well. The well encountered oil and gas but requires further evaluation. Further exploration drilling is planned to determine development potential of a second area of interest within the block. The Nursultan well is expected to spud in the first quarter of 2012. In addition, appraisal drilling and development studies continue for the next phase of Kashagan and the satellite fields of Kalamkas, Kairan and Aktote.

E&P OTHER

Greenland

Exploration

We were formally awarded Block 7011/11, Qamut, in December 2010 for oil and gas exploration in Baffin Bay, offshore Greenland. We own a 61.3 percent operating interest in the Qamut license. The work program, including 2-D seismic acquisitions, commenced in 2011.

Spill Containment

Marine Well Containment Company

In 2010, we formed a non-profit organization with Exxon Mobil Corporation, Chevron Corporation and Royal Dutch Shell plc to develop a new oil spill containment system and improve industry spill response in the Gulf of Mexico. Since its formation, several companies have joined the Marine Well Containment Company (MWCC).

In February 2011, MWCC launched an interim containment system, which provides rapid containment response capabilities in the event of an underwater well control incident in the deepwater Gulf of Mexico. MWCC is advancing this capability and is currently developing an expanded containment system with significantly increased capacity. The expanded containment system is expected to be available in 2012.

Subsea Well Response Project

During 2011, we, along with eight leading oil and gas companies, launched the Subsea Well Response Project (SWRP), an initiative designed to enhance the industry s capability to respond to international subsea well control incidents. SWRP is a non-profit organization based in Stavanger, Norway. This project complements the work being undertaken in the United States by MWCC and also in the United Kingdom by the Oil Spill Prevention and Response Advisory Group (OSPRAG). We are also a participant in OSPRAG.

Freeport 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. Market conditions currently favor the flow of LNG to European and Asian markets; therefore, 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.

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LNG Technology

Our Optimized Cascade® LNG liquefaction technology business continues to grow with the demand for new LNG plants. The technology has been applied in nine LNG trains around the world, and eight more are under construction.

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, 2011. No difference exists between our estimated total proved reserves for year-end 2010 and year-end 2009, which are shown in this filing, and estimates of these reserves shown in a filing with another federal agency in 2011.

DELIVERY COMMITMENTS

We sell crude oil and natural gas from our E&P producing operations under a variety of contractual arrangements, some of which specify the delivery of a fixed and determinable quantity. Our Commercial organization also enters into natural gas sales contracts where the source of the natural gas used to fulfill the contract can be the spot market or a combination of our reserves and the spot market. Worldwide, we are contractually committed to deliver approximately 5 trillion cubic feet of natural gas, including approximately 700 billion cubic feet related to the noncontrolling interests of consolidated subsidiaries, and 180 million barrels of crude oil in the future. These contracts have various expiration dates through the year 2029. 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 the Oil and Gas Operations section following the Notes to Consolidated Financial Statements, for information on the development of proved undeveloped reserves.

MIDSTREAM

At December 31, 2011, our Midstream segment represented 2 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 such as ethane, butane and propane and marketed as chemical feedstock, fuel or refinery blendstock. Total natural gas liquids extracted in 2011, including our share of DCP Midstream, averaged 200,000 barrels per day.

DCP Midstream is headquartered in Denver, Colorado. At December 31, 2011, DCP Midstream owned or operated 61 natural gas processing facilities, with a gross inlet capacity of 7.2 billion cubic feet per day of natural gas. Its natural gas pipeline systems included gathering services for these facilities, as well as natural gas transmission, and totaled approximately 62,000 miles of pipeline. At December 31, 2011, DCP Midstream also owned or operated 12 natural gas liquids fractionation plants, along with propane terminal facilities and natural gas liquids pipeline assets.

In 2011, DCP Midstream s raw natural gas throughput averaged 6.1 billion cubic feet per day, and natural gas liquids extraction averaged 383,000 barrels per day. 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.

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DCP Midstream markets a portion of its natural gas liquids to us and CPChem under a supply agreement whose volume commitments remain steady until December 31, 2014. This purchase commitment is on an if-produced, will-purchase basis and is expected to have a relatively stable purchase pattern over the remaining term of the contract. Under the agreement, natural gas liquids are purchased at various published market index prices, less transportation and fractionation fees.

DCP Midstream is constructing a natural gas processing plant in the Eagle Ford shale area of Texas. The plant, named the Eagle Plant, is expected to have a capacity of 200 million cubic feet per day and be accompanied by related natural gas liquids infrastructure. The Eagle Plant would increase DCP Midstream s total natural gas processing capacity in the area to 1 billion cubic feet per day and is expected to be online in the third quarter of 2012.

DCP Midstream is building a major natural gas liquids pipeline in Texas. The Sand Hills Pipeline is designed to provide new natural gas liquids transportation capacity from the Permian Basin and Eagle Ford shale area to markets in the Gulf Coast. The pipeline s initial capacity is expected to be 200,000 barrels per day, with expansion to 350,000 barrels per day possible. The pipeline will be phased into service, with completion of the first phase expected by the third quarter of 2012 to accommodate DCP Midstream s growing Eagle Ford liquids volumes. Service from the Permian Basin could be available as soon as the third quarter of 2013.

Outside of DCP Midstream, our U.S. natural gas liquids business includes the following:

- 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. Our net share of capacity is 24,300 barrels per day. In October 2010, Gulf Coast Fractionators announced plans to expand the capacity of its fractionation facility to 145,000 barrels per day, which would bring our net capacity to approximately 32,600 barrels per day. The expansion is expected to be operational in the second quarter of 2012.
- A 40 percent interest in a fractionation plant in Conway, Kansas. Our net share of capacity is 43,200 barrels per day.
- A 12.5 percent equity interest in a fractionation plant in Mont Belvieu, Texas. Our net share of capacity is 26,000 barrels per day.
- Marketing operations that optimize the flow of natural gas liquids and markets propane on a wholesale basis.

We also own a 39 percent equity interest in Phoenix Park Gas Processors Limited, which processes natural gas in Trinidad and markets natural gas liquids throughout the Atlantic Basin. Its facilities include a 2-billion-cubic-feet-per-day gas processing plant and a 70,000-barrel-per-day natural gas liquids fractionator. In 2011, our share of natural gas liquids extracted averaged 8,000 barrels per day, and our share of fractionated liquids averaged 16,000 barrels per day.

Upon completion of the separation of the downstream businesses, we expect all of our investments in Midstream will be included in Phillips 66, with the exception of the Gallup, New Mexico natural gas liquids fractionation plant and our equity interest in Phoenix Park.

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REFINING AND MARKETING (R&M)

At December 31, 2011, our R&M segment represented 24 percent of ConocoPhillips total assets. Our R&M segment primarily refines crude oil and other feedstocks into petroleum products (such as gasolines, distillates and aviation fuels); buys, sells and transports crude oil; and buys, transports, distributes and markets petroleum products. R&M has operations in the United States, Europe and Asia. The R&M segment does not include the results or statistics from our prior investment in LUKOIL, which are reported in our LUKOIL Investment segment.

Upon completion of the separation of the downstream businesses, we expect all of the assets within the R&M segment will be included in Phillips 66.

R&M UNITED STATES

Refining

At December 31, 2011, we owned or had an interest in 12 refineries in the United States.

			Thousands of Barrels Daily			
			Net Crude Throughput	Clean Product Capacity***		Clean Product Yield
Refinery	Location	Interest	Capacity	Gasolines	Distillates	Capability
East Coast Region						
Bayway	Linden, NJ	100%	238	145	115	90%
Trainer*	Trainer, PA	100	-	-	-	-
			238			
Gulf Coast Region						
Alliance	Belle Chasse, LA	100	247	125	120	86
Lake Charles	Westlake, LA	100	239	90	115	69
Sweeny	Old Ocean, TX	100	247	130	120	87
			733			
Central Region						
Wood River**	Roxana, IL	50	153	83	45	80
Borger**	Borger, TX	50	73	50	25	89
Ponca City	Ponca City, OK	100	187	105	80	91
Billings	Billings, MT	100	58	35	25	89
			471			
West Coast Region						
Ferndale	Ferndale, WA	100	100	55	30	75
Los Angeles	Carson/	100	139	80	65	87

	Wilmington, CA					
San Francisco	Arroyo Grande/ San Francisco, CA	100	120	55	55	83
			359			
			1,801			

* *Net throughput capacity of 185,000 barrels per day was idled effective October 1, 2011.*
** *Represents our proportionate share.*
*** *Clean Product Capacities are maximum rates for each clean product category, independent of each other. They are not additive when calculating the Clean Product Yield Capability for each refinery.*

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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									
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.*

East Coast Region

Bayway Refinery

The Bayway Refinery is located on the New York Harbor in Linden, New Jersey. Bayway refining units include one of the world s largest fluid catalytic cracking units, two hydrodesulfurization units, a reformer, alkylation unit and other processing equipment. The refinery produces a high percentage of transportation fuels, such as gasoline, diesel and jet fuel, as well as petrochemical feedstocks, residual fuel oil and home heating oil. Refined products are distributed to East Coast customers by pipeline, barge, railcar and truck. The complex also includes a 775-million-pound-per-year polypropylene plant.

Trainer Refinery

The Trainer Refinery is located on the Delaware River in Trainer, Pennsylvania. Refinery facilities include fluid catalytic cracking units, hydrodesulfurization units, a reformer and a hydrocracker. In September 2011, we announced our intention to sell the refinery and associated pipelines and terminals. We idled the facility effective October 1, 2011, and plan to permanently close the plant by the end of the first quarter of 2012 if a sales transaction is unsuccessful.

Gulf Coast Region

Alliance Refinery

The Alliance Refinery is located on the Mississippi River in Belle Chasse, Louisiana. The single-train facility includes fluid catalytic cracking units, hydrodesulfurization units and a reformer and aromatics unit. Alliance produces a high percentage of transportation fuels, such as gasoline, diesel and jet fuel. Other products include petrochemical feedstocks, home heating oil and anode petroleum coke. The majority of the refined products are distributed to customers in the southeastern and eastern United States through major common-carrier pipeline systems and by barge.

Lake Charles Refinery

The Lake Charles Refinery is located in Westlake, Louisiana. Its facilities include crude distillation, fluid catalytic cracker, hydrocracker, delayed coker and hydrodesulfurization units. The refinery produces a high percentage of transportation fuels, such as gasoline, off-road diesel and jet fuel, along with home heating oil. The majority of its refined products are distributed by truck, railcar, barge or major common-carrier pipelines to customers in the southeastern and eastern United States. Refined products can also be sold into export markets through the refinery s marine terminal. Refinery facilities also include a specialty coker and calciner, which produce graphite petroleum coke for the steel industry.

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Excel Paralubes

We own a 50 percent interest in Excel Paralubes, a joint venture which 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.

Sweeny Refinery

The Sweeny Refinery is located in Old Ocean, Texas, approximately 65 miles southwest of Houston. Refinery facilities include fluid catalytic cracking, delayed coking, alkylation, a continuous regeneration reformer and hydrodesulfurization units. The refinery receives crude oil via tankers, primarily through wholly owned and third-party terminals on the Gulf Coast, including a deepwater terminal at Freeport, Texas. It produces a high percentage of transportation fuels, such as gasoline, diesel and jet fuel. Other products include petrochemical feedstocks, home heating oil and coke. The refinery operates nearby terminals and storage facilities in Freeport, Jones Creek and on the San Bernard River, along with pipelines that connect these facilities to the refinery. Refined products are distributed throughout the Midwest and southeastern United States by pipeline, barge and railcar.

MSLP

Merey Sweeny, L.P. (MSLP) owns a delayed coker and related facilities at the Sweeny Refinery. MSLP processes long residue, which is produced from heavy sour crude oil, for a processing fee. Fuel-grade petroleum coke is produced as a by-product and becomes the property of MSLP. Prior to August 28, 2009, MSLP was owned 50/50 by us and PDVSA. Under the agreements that govern the relationships between the partners, certain defaults by PDVSA with respect to supply of crude oil to the Sweeny Refinery gave us the right to acquire PDVSA s 50 percent ownership interest in MSLP, which we exercised on August 28, 2009. PDVSA has initiated arbitration with the International Chamber of Commerce challenging the exercise of the call right and claiming it was invalid. The arbitral tribunal is scheduled to hold hearings on the merits of the dispute in December 2012. We continue to use the equity method of accounting for our investment in MSLP.

Central Region

WRB

We have two 50/50 North American heavy oil business ventures with Cenovus Energy Inc.: FCCL Partnership, a Canadian upstream general partnership, and WRB Refining LP, a U.S. downstream limited partnership. We are the operator and managing partner of WRB, which consists of the Wood River and Borger refineries. For additional information on FCCL, see the Exploration and Production (E&P) section.

WRB s processing capability of heavy Canadian or similar crudes was 145,000 barrels per day, after startup of the Keystone pipeline and prior to the finalization of the coker and refinery expansion (CORE) project at the Wood River Refinery. We have completed the CORE Project, and operational startup occurred in the fourth quarter of 2011. Test runs of the CORE Project have been successful to date and will continue through the first quarter of 2012. Upon completion of testing, total processing capability of heavy Canadian or similar crudes within WRB will be dependent on the quality of heavy Canadian crudes that are economically available, and is expected to range between 235,000 to 255,000 barrels per day.

Wood River Refinery

The Wood River Refinery is located in Roxana, Illinois, about 15 miles northeast of St. Louis, Missouri, at the convergence of the Mississippi and Missouri rivers. Operations include three distilling units, two fluid catalytic cracking units, hydrocracking, coking, reforming, hydrotreating and sulfur recovery. The refinery produces a high percentage of transportation fuels, such as gasoline, diesel and jet fuel. Other products include petrochemical feedstocks, asphalt and coke. Finished product leaves Wood River by pipeline, rail, barge and truck. The CORE Project has resulted in an increased clean product yield of 5 percent. Gross heavy crude oil capacity is expected to increase between 90,000 to 110,000 barrels per day, dependent on the quality of available heavy Canadian crudes. The majority of the existing asphalt production at Wood River will be replaced with production of upgraded products.

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Borger Refinery

The Borger Refinery is located in Borger, Texas, in the Texas Panhandle, approximately 50 miles north of Amarillo. The refinery facilities are comprised of coking, fluid catalytic cracking, hydrodesulfurization and naphtha reforming, in addition to a 45,000-barrels-per-day natural gas liquids fractionation facility. It produces a high percentage of transportation fuels, such as gasoline, diesel and jet fuel, as well as coke, natural gas liquids and solvents. Refined products are transported via pipelines from the refinery to West Texas, New Mexico, Colorado and the Midcontinent region.

Ponca City Refinery

The Ponca City Refinery is located in Ponca City, Oklahoma. It is a high-conversion facility which includes fluid catalytic cracking, delayed coking and hydrodesulfurization units. It produces a full range of products, including gasoline, diesel, jet fuel, liquefied petroleum gas (LPG) and anode-grade petroleum coke. Finished petroleum products are primarily shipped by company-owned and common-carrier pipelines to markets throughout the Midcontinent region.

Billings Refinery

The Billings Refinery is located in Billings, Montana. Its facilities include fluid catalytic cracking and hydrodesulfurization units, in addition to a delayed coker, which converts heavy, high-sulfur residue into higher value light oils. The refinery produces a high percentage of transportation fuels, such as gasoline, diesel and aviation fuels, as well as fuel-grade petroleum coke. Finished petroleum products from the refinery are delivered by pipeline, railcar and truck. The pipelines transport most of the refined products to markets in Montana, Wyoming, Utah and Washington.

West Coast Region

Ferndale Refinery

The Ferndale Refinery is located on Puget Sound in Ferndale, Washington, approximately 20 miles south of the U.S.-Canada border. Facilities include a fluid catalytic cracker, an alkylation unit, a diesel hydrotreater and an S-Zorb unit. The refinery produces transportation fuels such as gasoline and diesel. Other products include residual fuel oil, which supplies the northwest marine transportation market. Most refined products are distributed by pipeline and barge to major markets in the northwest United States.

Los Angeles Refinery

The Los Angeles Refinery consists of two linked facilities located about five miles apart in Carson and Wilmington, California, approximately 15 miles southeast of Los Angeles International Airport. Carson serves as the front end of the refinery by processing crude oil, and Wilmington serves as the back end by upgrading the intermediate products to finished products. The refinery produces a high percentage of transportation fuels, such as gasoline, diesel and jet fuel. Other products include fuel-grade petroleum coke. The refinery produces California Air Resources Board (CARB)-grade gasoline by blending ethanol to meet government-mandated oxygenate requirements. Refined products are distributed to customers in California, Nevada and Arizona by pipeline and truck.

San Francisco Refinery

The San Francisco Refinery consists of two facilities linked by a 200-mile pipeline. The Santa Maria facility is located in Arroyo Grande, California, about 200 miles south of San Francisco, while the Rodeo facility is in the San Francisco Bay Area. Semi-refined liquid products from the Santa Maria facility are sent by pipeline to the Rodeo facility for upgrading into finished petroleum products. The refinery produces a high percentage of transportation fuels, such as gasoline, diesel and jet fuel. Other products include petroleum coke. It also produces CARB-grade gasoline by blending ethanol to meet government-mandated oxygenate requirements. The majority of the refined products are distributed by pipeline, railcar and barge to customers in California.

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Marketing

In the United States, as of December 31, 2011, we marketed gasoline, diesel and aviation fuel through approximately 8,250 marketer-owned outlets in 49 states. The majority of these sites utilize the *Phillips 66*, *Conoco* or *76* brands.

Wholesale

At December 31, 2011, our wholesale operations utilized a network of marketers operating approximately 6,875 outlets that provided refined product offtake from our refineries. A strong emphasis is placed on the wholesale channel of trade because of its lower capital requirements. In addition, we held brand-licensing agreements with approximately 500 sites. 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, 2011, aviation gasoline and jet fuel were sold through dealers and independent marketers at approximately 875 *Phillips 66*-branded locations in the United States.

Lubricants

We manufacture and sell automotive, commercial and industrial lubricants which are marketed worldwide under the *Phillips 66, Conoco, 76* and *Kendall* brands, as well as other private label brands. We also manufacture Group II and import Group III base oils and market both under the respective brand names *Pure Performance* and *Ultra-S* globally.

Premium Coke & Polypropylene

We 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. We also manufacture and market polypropylene to North America under the *COPYLENE* brand name. Our *ThruPlus* Delayed Coker Technology, a proprietary process for upgrading heavy oil into higher value, light hydrocarbon liquids, was sold in June 2011.

Transportation

We supply feedstock to our refineries and distribute refined products to our customers via company-owned and common-carrier pipelines, barges, railcars and trucks.

Pipelines and Terminals

At December 31, 2011, R&M managed approximately 17,000 miles of common-carrier crude oil, raw natural gas liquids, natural gas and petroleum products pipeline systems in the United States, including those partially owned or operated by affiliates. In addition, we owned or operated 42 finished product terminals, 8 liquefied petroleum gas terminals, 5 crude oil terminals and 1 coke exporting facility.

In October 2011, we sold Seaway Products Pipeline Company to DCP Midstream. In December 2011, we sold our 16.55 percent equity interest in Colonial Pipeline Company and our 50 percent equity interest in Seaway Crude Pipeline Company.

Tankers

At December 31, 2011, we had 15 double-hulled crude oil tankers under charter, with capacities ranging in size from 713,000 to 2,100,000 barrels. These tankers are primarily used to transport feedstocks to certain of our U.S. refineries. In addition, we utilized five double-hulled product tankers, with capacities ranging from 315,000 to 332,000 barrels, to transport our heavy and clean products. The tankers discussed here exclude the operations of our subsidiary, Polar Tankers, Inc., which are discussed in the E&P section.

Specialty Businesses

We manufacture and sell a variety of specialty products including pipeline flow improvers and anode material for high-power lithium-ion batteries. Our specialty products are marketed under the *LiquidPower* and *CPreme* brand names.

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R&M INTERNATIONAL

Refining

At December 31, 2011, we owned or had an interest in four refineries outside the United States.

			Thousands of Barrels Daily			
			Net Crude			
				Clean Product		Clean
			Throughput	Capacity***		Product
Refinery	Location	Interest	Capacity	Gasolines	Distillates	Yield Capability
Humber	N. Lincolnshire, United Kingdom	100.00%	221	85	115	81%
Whitegate	Cork, Ireland	100.00	71	15	30	65
MiRO*	Karlsruhe, Germany	18.75	58	25	25	85
Melaka**	Melaka, Malaysia	47.00	76	20	50	80
			426			

**Mineraloelraffinerie Oberrhein GmbH.*
***Capacity increased to 80,000 barrels per day effective January 1, 2012.*
****Clean Product Capacities are maximum rates for each clean product category, independent of each other. They are not additive when calculating the Clean Product Yield Capability for each refinery.*

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

	Characteristics				Sources	
		Medium	Heavy	High	Europe	Middle East
	Sweet	Sour	Sour	TAN*	& FSU**	& Africa
Humber						
Whitegate						
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.*

Humber Refinery

The Humber Refinery is located on the east coast of England in North Lincolnshire, United Kingdom. It is a fully integrated refinery which produces a high percentage of transportation fuels, such as gasoline and diesel. Humber s facilities encompass fluid catalytic cracking, thermal cracking and coking. The refinery has two coking units with associated calcining plants, which upgrade the heaviest part of the crude barrel and imported feedstocks into light oil products and high-value graphite and anode petroleum cokes. Humber is the only coking refinery in the United Kingdom and is one of the world s largest producers of specialty graphite cokes and one of Europe s largest anode coke producers. Approximately 60 percent of the light oils produced in the refinery are marketed in the United Kingdom, while the other products are exported to the rest of Europe and the United States.

Whitegate Refinery

The Whitegate Refinery is located in Cork, Ireland, and is Ireland s only refinery. The refinery primarily produces transportation fuels, such as gasoline, diesel and fuel oil, which are distributed to the inland market, as well as being exported to Europe and the United States. We also operate a crude oil and products storage complex consisting of 7.5 million barrels of storage capacity and an offshore mooring buoy, located in Bantry Bay, about 80 miles southwest of the refinery in southern Cork County.

MiRO Refinery

The Mineraloelraffinerie Oberrhein GmbH (MiRO) Refinery, located on the Rhine River in Karlsruhe in southwest Germany, is a joint venture in which we own an 18.75 percent interest. Facilities include three crude unit trains, fluid catalytic cracking, petroleum coking and calcining, hydrodesulfurization units, reformers, isomerization and aromatics recovery units, ethyl tert-butyl ether (ETBE) and alkylation units. MiRO produces a high percentage of transportation fuels, such as gasoline and diesel. Other products include petrochemical feedstocks, home heating oil, bitumen, and anode- and fuel-grade petroleum coke. Refined products are delivered to customers in southwest Germany, northern Switzerland and western Austria by truck, railcar and barge.

Melaka Refinery

The Melaka Refinery in Melaka, Malaysia, is a joint venture refinery in which we own a 47 percent interest. Melaka produces a full range of refined petroleum products and capitalizes on coking technology to upgrade low-cost feedstocks into higher-margin products. An expansion project was completed during 2010 to increase crude oil conversion and treating unit capacities. Our share of refined products is transported by tanker and marketed in Malaysia and other Asian markets.

Wilhelmshaven Refinery

The Wilhelmshaven Refinery is located in the northern state of Lower Saxony in Germany, and has a 260,000 barrels-per-day crude oil processing capacity. We sold the refinery, tank farm and marine terminal in August 2011.

Marketing

At December 31, 2011, R&M had marketing operations in five European countries. Our marketing strategy is to sell primarily through owned, leased or joint venture retail sites using a low-cost, high-volume approach. 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, 2011, we had approximately 1,430 marketing outlets in our European operations, of which approximately 900 were company-owned and 330 were dealer-owned. We also held brand-licensing agreements with approximately 200 sites. Through our joint venture operations in Switzerland, we also have interests in 250 additional sites.

LUKOIL INVESTMENT

This segment represents our former investment in the ordinary shares of OAO LUKOIL, an international, integrated oil and gas company headquartered in Russia. We sold our remaining interest in LUKOIL in the first quarter of 2011. See Note 6 Investments, Loans and Long-Term Receivables, in the Notes to Consolidated Financial Statements, for more information.

CHEMICALS

At December 31, 2011, our Chemicals segment represented 2 percent of ConocoPhillips total assets. The Chemicals segment consists of our 50 percent equity investment in CPChem, a joint venture with Chevron Corporation, headquartered in The Woodlands, Texas. Upon completion of the separation of the downstream businesses, we expect our investment in the Chemicals segment will be included in Phillips 66.

CPChem s business is structured around two primary operating segments: Olefins & Polyolefins (O&P) and Specialties, Aromatics & Styrenics (SA&S). The O&P 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 SA&S segment manufactures and markets aromatics products, such as benzene, styrene, paraxylene and cyclohexane, as well as polystyrene and styrene-butadiene copolymers. SA&S also manufactures and markets a variety of specialty chemical products including organosulfur chemicals, solvents, drilling chemicals, mining chemicals and high-performance engineering plastics and compounds.

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CPChem s manufacturing facilities are located in Belgium, China, Colombia, Qatar, Saudi Arabia, Singapore, South Korea and the United States.

Key Projects

In October 2010, CPChem announced plans to build a 1-hexene plant capable of producing in excess of 200,000 metric tons per year at its Cedar Bayou Chemical Complex in Baytown, Texas. 1-hexene is a critical component used in the manufacture of polyethylene, a plastic resin commonly converted into film, plastic pipe, milk jugs, detergent bottles and food and beverage containers. Project planning has begun, with startup anticipated in 2014.

In November 2011, CPChem completed the acquisition of a polyalphaolefins (PAO) plant located in Beringen, Belgium. The addition of the plant more than doubled CPChem s PAO production capability. PAOs are used in many synthetic products, such as lubricants, greases and fluids, and have emerged as essential components in many industries and applications.

In December 2011, CPChem announced plans to pursue a project to construct a world-scale ethane cracker and two polyethylene facilities in the U.S. Gulf Coast Region. The project would leverage the development of significant shale gas resources in the United States. CPChem s Cedar Bayou facility in Baytown, Texas, would be the location of the 1.5-million-metric-tons-per-year ethylene unit. The two polyethylene facilities, each with an annual capacity of 500,000 metric tons, would be located at either the Cedar Bayou facility, or near CPChem s Sweeny facility in Old Ocean, Texas. Further evaluation will occur during 2012, with a final investment decision expected in 2013.

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), an additional joint venture in Mesaieed. The Q-Chem II facility produces polyethylene and normal alpha olefins (NAO) on a site adjacent to the Q-Chem complex. In connection with this project, an ethane cracker that provides ethylene feedstock via pipeline to the Q-Chem II plants was developed in Ras Laffan Industrial City, Qatar. The ethane cracker and pipeline are owned by Ras Laffan Olefins Company, a joint venture of Q-Chem II and Qatofin Company Limited. Q-Chem II s interests in the ethane cracker, pipeline and polyethylene and NAO plants are collectively referred to as Q-Chem II. Operational startup of Q-Chem II occurred in 2010.

Saudi Chevron Phillips Company (SCP) is a 50-percent-owned joint venture of CPChem that owns and operates an aromatics complex at Jubail Industrial City, Saudi Arabia. Jubail Chevron Phillips Company (JCP), another 50-percent-owned joint venture of CPChem, owns and operates an integrated styrene facility adjacent to the SCP aromatics complex. SCP and JCP are collectively known as S-Chem.

In December 2011, Saudi Polymers Company (SPCo), a 35-percent-owned joint venture company of CPChem, completed the construction of an integrated petrochemicals complex at Jubail Industrial City, Saudi Arabia. SPCo will produce ethylene, propylene, polyethylene, polypropylene, polystyrene and 1-hexene. Commercial production is expected in 2012.

EMERGING BUSINESSES

At December 31, 2011, our Emerging Businesses segment represented 1 percent of ConocoPhillips total assets. The segment encompasses the development of new technologies and businesses outside our normal operations. Activities within this segment are focused on power generation and new technologies related to conventional and nonconventional hydrocarbon recovery, refining, alternative energy, biofuels and the environment. Upon completion of the separation of the downstream businesses, we expect our power generation assets and certain technology operations will be included in Phillips 66.

Power Generation

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, the following projects have a significant merchant component and are included in the Emerging Businesses segment:

- The Immingham Combined Heat and Power Plant, a wholly owned 1,180-megawatt facility in the United Kingdom, which provides steam and electricity to the Humber Refinery and steam to a neighboring refinery, as well as merchant power into the U.K. market.
- Sweeny Cogeneration LP, our 50 percent joint venture near the Sweeny Refinery complex.

Technology Development

Our Technology group focuses on developing new business opportunities designed to provide future growth prospects for ConocoPhillips. Focus areas include advanced hydrocarbon processes, energy efficiency technologies, new petroleum-based products, renewable fuels and carbon capture and conversion technologies. We are progressing the technology development of second-generation biofuels with Iowa State University, the Colorado Center for Biorefining and Biofuels and Archer Daniels Midland. We have also established a relationship with the University of Texas Energy Institute to collaborate on emerging technologies. Internally, we are continuing to evaluate wind, solar and geothermal investment opportunities. We also invest in technologies to find more efficient, economical and environmentally sound ways to produce oil and natural gas by focusing on our oil sands position, the rapid growth from unconventional reservoirs and advances in subsurface technologies.

In 2011, we formed Energy Technology Ventures (ETV), a joint venture with General Electric Capital and NRG Energy, Inc., which focuses on the development of next generation energy technology. ETV invests in, and offers commercial collaboration opportunities to, venture- and growth-stage energy technology companies in the renewable power generation, smart grid, energy efficiency, oil, natural gas, coal and nuclear energy, emission controls and biofuels sectors.

In addition, we operate a Global Water Sustainability Center in Qatar, which researches and develops water solutions for the petroleum, petrochemical, municipal and agricultural sectors.

We offer a gasification technology (E-Gas Technology) 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, substitute natural gas, hydrogen and chemicals. This clean, efficient technology facilitates carbon capture and storage, as well as minimizes criteria pollutant emissions and reduces water consumption. E-Gas Technology has been utilized in commercial applications since 1987 and is currently licensed to third parties. We have licensed E-Gas Technology in Asia and North America, and are pursuing several additional licensing opportunities.

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.

Our E&P segment competes with numerous other companies in the industry, including state-owned companies, to locate and obtain new sources of supply and to produce oil, bitumen, natural gas liquids and natural gas in an efficient, cost-effective manner. Based on publicly available year-end 2010 reserves statistics, we had the seventh-largest total of worldwide proved reserves of nongovernment-controlled companies. We deliver our production into the worldwide commodity markets. Principal methods of competing include geological, geophysical and engineering research and technology; experience and expertise; economic analysis in connection with portfolio management; and operating efficient oil and gas producing properties.

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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 extractor 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.

Our R&M segment competes primarily in the United States, Europe and Asia. Based on the statistics published in the December 5, 2011, issue of the *Oil & Gas Journal*, we are one of the largest refiners of petroleum products in the United States. Worldwide, our refining capacity ranked in the top ten 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 2011 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 efficient 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 2011, we held a total of 1,229 active patents in 63 countries worldwide, including 525 active U.S. patents. During 2011, we received 52 patents in the United States and 70 foreign patents. Our products and processes generated licensing revenues of $136 million in 2011. 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 $267 million, $230 million and $190 million in 2011, 2010 and 2009, respectively.

Our Health, Safety and Environment (HSE) organization provides tools and support to our business units and staff groups to help them ensure consistent health, safety and environmental excellence. In support of the goal of zero incidents, we have implemented an HSE Excellence process, which enables business units to measure their performance and compliance with our HSE Management System requirements, identify gaps, and develop improvement plans. Assessments are conducted annually to capture progress and set new targets. We are also committed to continuously improving process safety and preventing releases of hazardous materials.

The environmental information contained in Management s Discussion and Analysis of Financial Condition and Results of Operations on pages 64 through 67 under the captions Environmental and Climate Change is incorporated herein by reference. It includes information on expensed and capitalized environmental costs for 2011 and those expected for 2012 and 2013.

Web Site Access to SEC Reports

Our Internet Web site address is *http://www.conocophillips.com*. Information contained on our Internet Web site is not part of this report on Form 10-K.

Our Annual Reports on Form 10-K, Quarterly Reports on Form 10-Q, Current Reports on Form 8-K and any amendments to these reports filed or furnished pursuant to Section 13(a) or 15(d) of the Securities Exchange Act of 1934 are available on our Web site, free of charge, as soon as reasonably practicable after such reports are filed with, or furnished to, the SEC. Alternatively, you may access these reports at the SEC s Web site at *http://www.sec.gov*.

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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, bitumen, natural gas, natural gas liquids, LNG and refined products. The factors influencing these prices are beyond our control. Lower crude oil, bitumen, natural gas, natural gas liquids, LNG 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, bitumen and natural gas production will decline, resulting in an adverse impact to our business.

The rate of production from upstream fields 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, bitumen and natural gas we produce with good prospects for future production, our business will experience reduced cash flows and results of operations.

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

Our proved reserve information included in this annual report has been derived from engineering estimates prepared or reviewed by our personnel. Any significant future price changes could 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 process that involves estimating volumes to be recovered from underground accumulations of crude oil, bitumen 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 material 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, and greenhouse gas emissions as they are, or may become, regulated).
- 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.
- Exploration and production activities in certain areas, such as offshore environments, arctic fields, oil sands reservoirs and shale gas plays.

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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.

Although our business operations are designed and operated to accommodate expected climatic conditions, to the extent there are significant changes in the Earth s climate, such as more severe or frequent weather conditions in the markets we serve or the areas where our assets reside, we could incur increased expenses, our operations could be materially impacted, and demand for our products could fall.

In addition, in response to the Deepwater Horizon incident, the United States, as well as other countries where we do business, may make changes to their laws or regulations governing offshore operations that could have a material adverse effect on our business.

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 may continue to do so in the future.

Local political and economic factors in international markets could have a material adverse effect on us. Approximately 60 percent of our hydrocarbon production was derived from production outside the United States in 2011, and 56 percent of our proved reserves, as of December 31, 2011, was 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, bitumen, natural gas, natural gas liquids or refined product pricing and taxation, other political, economic or diplomatic developments, changing political conditions and international monetary fluctuations.

Changes in governmental regulations may impose price controls and limitations on production of crude oil, bitumen 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, bitumen and natural gas wells below actual production capacity in order to conserve supplies of crude oil, bitumen 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 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 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.

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We do not insure against all potential losses; and therefore, we could be harmed by unexpected liabilities and increased costs.

We maintain insurance against many, but not all, potential losses or liabilities arising from operating risks. As such, our insurance coverage may not be sufficient to fully cover us against potential losses arising from such risks. Uninsured losses and liabilities arising from operating risks could reduce the funds available to us for capital, exploration and investment spending and could have a material adverse effect on our business, financial condition, results of operations and cash flows.

Our operations present hazards and risks that require significant and continuous oversight.

The scope and nature of our operations present a variety of significant hazards and risks, including operational hazards and risks such as explosions, fires, pipeline interruptions, pipeline ruptures, crude oil or refined products spills, severe weather, geological events, labor disputes, or cyber attacks. Our operations are also subject to the additional hazards of pollution, releases of toxic gas and other environmental hazards and risks. All such hazards could result in loss of human life, significant property and equipment damage, environmental pollution, impairment of operations, substantial losses to us and damage to our reputation.

The proposed separation of our downstream businesses is contingent upon the satisfaction of a number of conditions, which may not be consummated on the terms or timeline currently contemplated or may not achieve the intended results.

We expect the separation will be effective in the second quarter of 2012. Our ability to timely effect the separation is subject to several conditions, including, among others, the receipt of a favorable private letter ruling from the IRS and the SEC declaring effective a registration statement relating to the securities of Phillips 66. We cannot assure we will be able to complete the separation in a timely fashion, if at all. For these and other reasons, the separation may not be completed on the terms or timeline contemplated. Further, if the separation is completed, it may not achieve the intended results. Any such difficulties could adversely affect our business, results of operations or financial condition.

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 2011, as well as matters previously reported in our 2010 Form 10-K and our

first-, second- and third-quarter 2011 Form 10-Qs that were not resolved prior to the fourth quarter of 2011. 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 SEC regulations.

Our U.S. refineries are implementing two separate consent decrees, regarding alleged violations of the Federal Clean Air Act, with the Environmental Protection Agency (EPA), six states and one local air pollution agency. Some of the requirements and limitations contained in the decrees 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 decrees or other reports required by permits or regulations, we occasionally report matters that could be subject to a request for stipulated penalties. If a specific request for stipulated penalties meeting the reporting threshold set forth in SEC 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.

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New Matters

In December 2011, ConocoPhillips was notified by the EPA of alleged violations related to the use of Renewable Identification Numbers (RINs). The EPA intends to present an administrative settlement agreement to resolve the alleged violations under which it would seek a penalty of $250,000. ConocoPhillips is working with the EPA to resolve this matter.

On November 28, 2011, the Borger Refinery received a Notice of Enforcement from the Texas Commission on Environmental Quality (TCEQ) for alleged emissions events that occurred during inclement weather in January and February 2011. The TCEQ is seeking a penalty of $120,000. ConocoPhillips is working with TCEQ to resolve this matter.

In October 2011, ConocoPhillips was notified by the Attorney General of the State of California it was conducting an investigation into possible violations of the regulations relating to the operation of underground storage tanks at gas stations in California. ConocoPhillips is contesting these allegations.

Matters Previously Reported

On April 13, 2011, ConocoPhillips received a Notice of Enforcement and Proposed Agreed Order from the TCEQ seeking a penalty to settle several violations of air pollution control regulations and/or facility permit conditions at the Borger Refinery. These violations were previously disclosed on the ConocoPhillips Borger Refinery Title V deviation report. The TCEQ approved the settlement of this matter on October 18, 2011, with payment of a $70,963 penalty and a $70,962 Supplemental Environmental Project. This matter is now resolved.

In October 2007, we received a Complaint from the 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. ConocoPhillips is working with the EPA and the U.S. Coast Guard to resolve this matter.

In 2009, ConocoPhillips notified the EPA and the U.S. Department of Justice (DOJ) it had self-identified certain compliance issues related to Benzene Waste Operations National Emission Standard for Hazardous Air Pollutants requirements at its Trainer, Pennsylvania, and Borger, Texas, facilities. On January 6, 2010, the DOJ provided its initial penalty demand for this matter as part of our confidential settlement negotiations. ConocoPhillips has reached an agreement with the EPA and DOJ regarding an appropriate penalty amount, which will be reflected in the third amendment to the consent decree in Civil Action No. H-05-258 (the agreed-upon penalty amount remains confidential until that time).

On May 19, 2010, the Lake Charles Louisiana Refinery received a Consolidated Compliance Order and Notice of Potential Penalty from the Louisiana Department of Environmental Quality (LDEQ) alleging various violations of applicable air emission regulations, as well as certain provisions of the consent decree in Civil Action No. H-01-4430. ConocoPhillips is working with the LDEQ to resolve this matter.

In October 2003, the District Attorney s Office in Sacramento, California, filed a complaint in California 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. On December 19, 2011, the Court approved a settlement of this lawsuit which includes the payment of $500,000 which will be treated as a civil penalty. This matter is now resolved.

Item 4. MINE SAFETY DISCLOSURES

Not applicable.

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EXECUTIVE OFFICERS OF THE REGISTRANT

Name	Position Held	Age*
Willie C. W. Chiang	Senior Vice President, Refining, Marketing, Transportation and Commercial	51
Greg C. Garland	Senior Vice President, Exploration and Production Americas	54
Alan J. Hirshberg	Senior Vice President, Planning and Strategy	50
Janet L. Kelly	Senior Vice President, Legal, General Counsel and Corporate Secretary	54
Ryan M. Lance	Senior Vice President, Exploration and Production International	49
James J. Mulva	Chairman of the Board of Directors, President and Chief Executive Officer	65
Glenda M. Schwarz	Vice President and Controller	46
Jeff W. Sheets	Senior Vice President, Finance and Chief Financial Officer	54

**On February 15, 2012.*

There are no family relationships among any of 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 the date of election until the first meeting of the directors held after the next Annual Meeting of Stockholders or until a successor is elected. The date of the next annual meeting is May 9, 2012. Set forth below is information about the executive officers.

Willie C. W. Chiang was appointed Senior Vice President, Refining, Marketing, Transportation and Commercial in October 2010. He previously served as Senior Vice President, Refining, Marketing and Transportation from 2008 to October 2010; Senior Vice President, Commercial from 2007 to 2008; and President, Americas Supply & Trading, Commercial, from 2005 through 2007.

Greg C. Garland was appointed Senior Vice President, Exploration and Production Americas in October 2010, having previously served as President and Chief Executive Officer of CPChem since 2008. Prior to that, he served as Senior Vice President, Planning and Specialty Products at CPChem from 2000 to 2008.

Alan J. Hirshberg was appointed Senior Vice President, Planning and Strategy in October 2010. Prior to that, he was employed by Exxon Mobil Corporation and served as Vice President, Worldwide Deepwater and Africa Projects since 2009; Vice President, Worldwide Deepwater Projects from 2008 to 2009; Vice President, Established Areas Projects from 2006 to 2008; and Vice President, Operated by Others Projects in 2006.

Janet L. Kelly was appointed Senior Vice President, Legal, General Counsel and Corporate Secretary in 2007, having previously served as Deputy General Counsel since 2006.

Ryan M. Lance was appointed Senior Vice President, Exploration and Production International, in May 2009. Prior to that, he served as President, Exploration and Production Asia, Africa, Middle East and Russia/Caspian since April 2009; President, Exploration and Production Europe, Asia, Africa and the Middle East from 2007 to 2009; Senior Vice President, Technology in 2007; and Senior Vice President, Technology and Major Projects since 2006.

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James J. Mulva has served as Chairman of the Board of Directors, President and Chief Executive Officer since May 2011, having previously served as Chairman of the Board of Directors and Chief Executive Officer since October 2008. He previously served as Chairman of the Board of Directors, President and Chief Executive Officer since 2004.

Glenda M. Schwarz was appointed Vice President and Controller in 2009. She previously served as General Auditor and Chief Ethics Officer from 2008 to 2009, having previously served as General Manager, Downstream Finance and Performance Analysis since 2005.

Jeff W. Sheets was appointed Senior Vice President, Finance and Chief Financial Officer in October 2010. Prior to that, he served as Senior Vice President, Planning and Strategy since 2008, having previously served as Vice President and Treasurer since the merger.

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PART II

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

Quarterly Common Stock Prices and Cash Dividends Per Share

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

	Stock Price High	Low	Dividends
2011			
First	**$ 81.80**	**66.50**	**.66**
Second	**81.75**	**70.08**	**.66**
Third	**80.13**	**60.40**	**.66**
Fourth	**73.90**	**58.65**	**.66**
2010			
First	$ 53.80	46.63	.50
Second	60.53	48.51	.55
Third	58.03	48.06	.55
Fourth	68.58	56.80	.55

Closing Stock Price at December 31, 2011	$ 72.87
Closing Stock Price at January 31, 2012	$ 68.21
Number of Stockholders of Record at January 31, 2012*	57,800

**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, 2011	15,727,577	$ 66.77	15,724,559	$ 2,100

November 1-30, 2011	15,108,133		70.21	15,108,040	1,039
December 1-31, 2011	14,726,654		70.60	14,720,228	10,000
Total	45,562,364	$	69.15	45,552,827	

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

** *On March 24, 2010, we announced plans to repurchase up to $5 billion of our common stock through 2011. Share repurchases under this program were completed in the first quarter of 2011. On February 11, 2011, we announced plans to repurchase up to $10 billion of our common stock over the subsequent two years. Share repurchases under this program were completed in the fourth quarter of 2011. On December 2, 2011, we announced a share repurchase program for a further $10 billion of common stock over the next two years. Acquisitions for the share repurchase program 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 plan are held as treasury shares.*

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Item 6. SELECTED FINANCIAL DATA

	Millions of Dollars Except Per Share Amounts				
	2011	2010	2009	2008	2007
Sales and other operating revenues	$ **244,813**	189,441	149,341	240,842	187,437
Net income (loss)	**12,502**	11,417	4,492	(16,279)	11,545
Net income (loss) attributable to ConocoPhillips	**12,436**	11,358	4,414	(16,349)	11,458
Per common share					
Basic	**9.04**	7.68	2.96	(10.73)	7.06
Diluted	**8.97**	7.62	2.94	(10.73)	6.96
Total assets	**153,230**	156,314	152,138	142,865	177,094
Long-term debt	**21,610**	22,656	26,925	27,085	20,289
Joint venture acquisition obligation long-term	**3,582**	4,314	5,009	5,669	6,294
Cash dividends declared per common share	**2.64**	2.15	1.91	1.88	1.64

Many factors can impact the comparability of this information, such as:

The financial data for 2010 includes the impact of $5,803 million before-tax ($4,583 million after-tax) related to gains from asset dispositions and LUKOIL share sales.

The financial data for 2008 includes the impact of impairments related to goodwill and to our LUKOIL investment that together amount to $32,939 million before- and after-tax.

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.

See Management s Discussion and Analysis of Financial Condition and Results of Operations and the Notes to Consolidated Financial Statements for a discussion of factors that will enhance an understanding of this data.

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Item 7. MANAGEMENT S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS
February 21, 2012

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 anticipate, estimate, believe, budget, continue, could, intend, may, plan, potential, predict, seek, should, will, would, expect goal, guidance, outlook, effort, target and similar expressions identify forward-looking statements. The company does not undertake to upda 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 73.

The terms earnings and loss as used in Management s Discussion and Analysis refer to net income (loss) attributable to ConocoPhillips.

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 29,800 employees worldwide, and at year-end 2011 had assets of $153 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, bitumen, natural gas, liquefied natural gas (LNG) 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 past investment in the ordinary shares of OAO LUKOIL, an international, integrated oil and gas company headquartered in Russia. We completed the divestiture of our entire interest in LUKOIL in the first quarter of 2011.
- **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.

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Our earnings depend largely on the profitability of our E&P and R&M segments. Crude oil and natural gas prices, along with refining margins, are the most significant factors affecting our profitability. In recent years, the business environment for the energy industry has experienced extreme volatility. As a result, in late 2009, we announced several strategic initiatives designed to improve our financial position and increase returns on capital. We have made significant progress on our three-year strategic plan through portfolio optimization, debt reduction and increased shareholder distributions. During 2011, we announced plans to sell an additional $5 $10 billion of noncore assets over the next two years, bringing the total asset divestiture program target to $15 $20 billion for the years 2010 through 2012. As of year-end 2011, we have generated approximately $10.7 billion from asset dispositions, the proceeds of which were primarily targeted toward share repurchases and debt reduction.

We also completed the sale of our entire interest in LUKOIL in the first quarter of 2011, which generated total proceeds of $9.5 billion in 2010 and 2011. These proceeds were largely used to fund share repurchases. In December 2011, our Board authorized the additional purchase of up to $10 billion of our common stock over the next two years. This increased the share repurchase program from $15 billion to $25 billion. Since the inception of the share repurchase programs, we have repurchased 15 percent of our shares outstanding for a total of $15 billion. During 2011, we also increased the amount of our quarterly dividend rate by 20 percent, paid dividends on our common stock of $3.6 billion for the full year and reduced our debt by 4 percent.

Our total capital program in 2012 is expected to be $15.5 billion, a $1.5 billion increase from $14.0 billion in 2011. We also expect 2012 production to be approximately 1.6 million barrels of oil equivalent per day (BOED), excluding the impact of any additional asset sales.

Consistent with our strategy to focus on value creation for our shareholders, in July 2011, our Board approved pursuing the separation of our refining, marketing and transportation businesses into a stand-alone, publicly traded corporation via a tax-free distribution. The new downstream company, named Phillips 66, will also include most of our Midstream segment, our Chemicals segment, as well as our power generation and certain technology operations included in our Emerging Businesses segment. We believe the separation will enable each company to pursue a more focused strategy, which will enable the management of each company to concentrate their resources on its particular market segments, customers and core businesses. The separation is subject to market conditions, customary regulatory approvals, the receipt of an affirmative Internal Revenue Service private letter ruling and final Board approval, and is expected to be completed in the second quarter of 2012.

Upon completion of the separation, ConocoPhillips will be a large and geographically diverse pure-play exploration and production company. Our strategy of enhancing returns on capital through developing new resources, growing reserves and production per share, continuing the asset sale program and increasing shareholder distributions will not change.

Phillips 66 will be an integrated downstream company, with operations encompassing natural gas gathering and processing, crude oil refining, petroleum products marketing, transportation, power generation and petrochemicals manufacturing and marketing.

We believe the execution of our strategic plan will position the two companies to be successful and competitive in the long term. Other important factors that we must continue to manage well in order to sustain our long-term competitive position include:

- Operating our producing properties and refining and marketing operations safely, consistently and in an environmentally sound manner. Safety is our first priority, and we are committed to protecting the health and safety of everyone who has a role in our operations and the communities in which we operate. Optimizing 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 2011, our worldwide refining capacity utilization rate was 92 percent, compared with 81 percent in 2010. The increase in 2011 primarily resulted from the removal of the Wilhelmshaven Refinery (WRG) from our refining capacities effective January 1, 2011, and lower turnaround activity, partially offset by higher planned maintenance.

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There has been heightened public focus on the safety of the oil and gas industry as a result of the 2010 Deepwater Horizon incident in the Gulf of Mexico. Safety and environmental stewardship, including the operating integrity of our assets, remain our highest priorities. In 2010, we formed a non-profit organization, the Marine Well Containment Company LLC (MWCC), with Exxon Mobil Corporation, Chevron Corporation and Royal Dutch Shell plc, to develop a new oil spill containment system and improve industry spill response in the U.S. Gulf of Mexico. To complement this work internationally, in 2011, we and several leading oil and gas companies established the Subsea Well Response Project in Norway, and we participated in the Oil Spill Prevention and Response Advisory Group in the United Kingdom.

Adding to our proved reserve base. We primarily add to our proved reserve base in three ways:

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

Through a combination of the methods listed above, we have been successful in the past in maintaining or adding to our production and proved reserve base, and we anticipate being able to do so in the future. In the five years ended December 31, 2011, our reserve replacement was 102 percent, excluding LUKOIL and the impact of acquisitions, dispositions and expropriations.

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.

Controlling costs and expenses. 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, is a high priority. We monitor these costs using various methodologies that are reported to senior management monthly, on both an absolute-dollar basis and a per-unit basis. Because managing operating and overhead costs is critical to maintaining competitive positions in our industries, cost control is a component of our variable compensation programs. Operating and overhead costs increased 1 percent in 2011, compared with 2010.

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, construct pipelines and LNG facilities, or continue to maintain and improve our refinery complexes. We invest in 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 the investment is operational and begins generating financial returns.

The capital expenditures and investments portion of our capital program totaled $13.3 billion in 2011, and we anticipate capital expenditures and investments to be approximately $14.8 billion in 2012. The increase reflects our strategic emphasis on delivering value by investing in the most profitable opportunities. We expect competitive returns from increased investments in unconventional resource projects, such as our oil sands business in Canada, liquids-rich shale plays in the U.S. Lower 48 and the Australia Pacific LNG (APLNG) joint venture. As our production profile adjusts over time to reflect our increased levels of investment in liquids plays and lower levels in North American conventional natural gas, we expect higher returns in E&P, absent changes in market factors.

Managing our asset portfolio. We continually evaluate our assets to determine whether they fit our strategic plans or should be sold or otherwise disposed. As part of our $15 $20 billion asset divestiture program for 2010 2012, during 2010, we sold our 9.03 percent interest in the Syncrude oil

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sands mining operation; our 50 percent interest in CFJ Properties, a joint venture which owned and operated *Flying J*-branded truck and travel plazas; and several E&P properties located in the Lower 48 and western Canada. In 2011, we continued to divest low-return, noncore assets in the Lower 48 and western Canada. We also sold WRG, Seaway Products Pipeline Company, and our equity interests in Colonial Pipeline Company and Seaway Crude Pipeline Company. Additionally, we completed the divestiture of our entire interest in LUKOIL in the first quarter of 2011.

East Coast refining has been under severe market pressure for several years. As a result, in September 2011, we announced our intention to sell the Trainer Refinery located in Trainer, Pennsylvania. The refinery has been idled and will permanently close by the end of the first quarter of 2012 if a sales transaction is unsuccessful. In addition, in E&P we recently entered into agreements to sell our Vietnam business, as well as certain North Sea assets. These sales are expected to close in the first half of 2012.

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.

Other significant factors that can affect our profitability include:

Commodity prices. In 2011, the global economic rate of growth slowed, leading to lower oil demand growth. Oil prices, however, increased in 2011, as supply concerns, including concerns over the loss of Libyan production, outweighed the economic uncertainty in the United States and Europe. U.S. natural gas prices remained under pressure during 2011, as increased production from shale plays outpaced demand growth. As a result, storage inventory levels reached record highs by the end of 2011. We expect these factors will continue to moderate natural gas prices, resulting in limited U.S. LNG imports in the near- to mid-term.

In recent years, the use of hydraulic fracturing in shale natural gas formations has led to increased industry actual and forecasted natural gas production in the United States. Although providing short- and long-term significant growth opportunities for our company, the increased abundance of natural gas due to development of shale plays could also have adverse financial implications to us, including: an extended period of low natural gas prices; production curtailments on properties that produce primarily natural gas; cancelation or delay of plans to develop Alaska North Slope and Canadian Arctic natural gas fields; and underutilization of LNG regasification facilities and certain natural gas pipelines. Should one or more of these events occur, our revenues would be reduced and additional impairments might be possible.

Impairments. As mentioned above, we participate in capital-intensive industries. At times, our investments become impaired when, for example, our reserve estimates are revised downward, commodity prices or refining margins decline significantly for long periods of time, or 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 which, if exploratory drilling proves unsuccessful, could lead to a material impairment of leasehold values. Before-tax impairments in 2011 totaled $1.3 billion and primarily resulted from the impairments of the Trainer Refinery, our equity investment in Naraynmarneftegaz (NMNG) and certain Canadian natural gas properties. Before-tax impairments in 2010 totaled $2.4 billion and primarily related to the $1.5 billion property impairment of WRG and the $0.6 billion impairment of our equity investment in NMNG.

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.

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Fiscal and regulatory environment. Our operations, primarily in E&P, can be affected by changing economic, regulatory and political environments in the various countries in which we operate, including the United States. Civil unrest or strained relationships with governments may impact our operations or investments. These changing environments have generally negatively impacted our results of operations, and further changes to government fiscal take could have a negative impact on future operations. Our production operations in Libya and related oil exports were temporarily suspended in 2011 during Libya s period of civil unrest. Our assets in Venezuela and Ecuador were expropriated in 2007 and 2009, respectively. In Canada, the Alberta provincial government changed the royalty structure in 2009 to tie a component of the new rate to prevailing prices. Our management carefully considers these events when evaluating projects or determining the level of activity in such countries.

Segment Analysis

Earnings for the E&P segment are generally closely aligned with industry price levels for crude oil and natural gas. 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 2011, compared with 2010, averaging $95.05 per barrel in 2011, an increase of 20 percent. Industry natural gas prices at Henry Hub decreased 8 percent during 2011 to an average price of $4.04 per million British thermal units.

The Midstream segment s results are most closely linked to natural gas liquids prices. The most important factor affecting 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 23 percent in 2011.

Refining margins, refinery capacity utilization and cost control 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. Global refining margins significantly improved during 2011, compared with 2010. The U.S. 3:2:1 crack spread, which is primarily WTI-based, increased 126 percent in 2011, while the N.W. Europe benchmark increased 20 percent. The improvement in domestic refining margins primarily resulted from increased production from shale plays and high inventory levels in the Midcontinent area, causing WTI to trade at a deeper discount relative to waterborne crudes for most of 2011. This discount, however, began to narrow toward the end of 2011. During the periods of large WTI-Brent spreads, refineries capable of processing WTI and crude oils that are WTI-based benefitted from the lower regional feedstock prices. In contrast, East Coast refining, which relies primarily on Brent-based crudes, has been under severe market pressure. Product imports, weakness in motor fuel demand, and costly regulatory requirements are key challenges in this difficult environment.

The LUKOIL Investment segment consisted of our prior investment in the ordinary shares of LUKOIL. We disposed of our remaining interest in LUKOIL in the first quarter of 2011.

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, refining, alternative energy, biofuels and the environment. Some of these technologies have the potential to become important drivers of profitability in future years.

Our key performance indicators are shown in the statistical tables provided at the beginning of the operating segment sections that follow. These include commodity prices, production and refining capacity utilization.

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RESULTS OF OPERATIONS

Consolidated Results

A summary of the company s net income attributable to ConocoPhillips by business segment follows:

	Millions of Dollars		
Years Ended December 31	**2011**	2010	2009
E&P	**$ 8,242**	9,198	3,604
Midstream	**458**	306	313
R&M	**3,751**	192	37
LUKOIL Investment	**239**	2,503	1,219
Chemicals	**745**	498	248
Emerging Businesses	**(26)**	(59)	3
Corporate and Other	**(973)**	(1,280)	(1,010)
Net income attributable to ConocoPhillips	**$ 12,436**	11,358	4,414

2011 vs. 2010

Earnings for ConocoPhillips increased 9 percent in 2011. The improvement was mainly due to:

- Higher commodity prices in our E&P segment. Commodity price benefits were somewhat offset by increased production taxes.
- Improved results from our R&M operations, reflecting significantly higher U.S. refining margins.
- Lower impairments. In 2011, impairments totaled $1,004 million after-tax, compared with 2010 impairments of $1,928 million after-tax.

These items were partially offset by:

- Lower gains from asset sales. In 2011, gains from asset dispositions and LUKOIL share sales were $1,637 million after-tax, compared with 2010 gains of $4,583 million after-tax.
- The absence of equity earnings from LUKOIL due to the divestiture of our interest.
- Lower production volumes from our E&P segment.

2010 vs. 2009

The improved results in 2010 were primarily the result of:

- Higher prices for crude oil, natural gas, natural gas liquids (NGL) and LNG in our E&P segment. Commodity price benefits were somewhat offset by increased production taxes.
- Gains of $4,583 million after-tax from asset dispositions and LUKOIL share sales.
- Improved results from our domestic R&M operations, reflecting higher refining margins.

These items were partially offset by:

Impairments totaling $1,928 million after-tax.
Lower production volumes from our E&P segment.

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Income Statement Analysis

2011 vs. 2010

Sales and other operating revenues increased 29 percent in 2011, while purchased crude oil, natural gas and products increased 37 percent. The increases were mainly due to significantly higher prices for petroleum products, crude oil and NGLs.

Equity in earnings of affiliates increased 30 percent in 2011. The increase primarily resulted from:

- Earnings from Qatar Liquefied Gas Company Limited (3) (QG3), primarily due to sales of LNG following production startup, which occurred in October 2010.
- Improved earnings from WRB Refining LP, primarily due to higher refining margins.
- Improved earnings from CPChem, mainly due to higher margins in the olefins and polyolefins business line.
- Lower impairments from NMNG. In 2011, equity earnings included a $395 million impairment of our equity investment, and 2010 equity earnings included a $645 million impairment.
- Improved earnings from FCCL Partnership, mostly due to higher commodity prices and volumes.
- Improved earnings from DCP Midstream, LLC, mainly as a result of higher NGL prices.

These increases were partially offset by the absence of equity earnings from LUKOIL due to the divestiture of our interest.

Gain on dispositions decreased 65 percent in 2011. Gains in 2011 primarily resulted from the disposition of Seaway Products Pipeline Company, our interests in Seaway Crude Pipeline Company and Colonial Pipeline Company, certain E&P assets located in the Lower 48 and Canada, and the remaining divestiture of our LUKOIL shares. These gains were partially offset by the loss on dilution of our equity interest in APLNG from 50 percent to 42.5 percent and the loss on disposition of WRG. Gains in 2010 primarily reflected the $2,878 million gain realized from the sale of our interest in Syncrude, the $1,749 million gain on the divestiture of our LUKOIL shares, gains on the disposition of certain E&P assets located in the Lower 48 and Canada, and the gain on sale of our 50 percent interest in CFJ Properties. For additional information, see Note 5 Assets Held for Sale or Sold and Note 6 Investments, Loans and Long-Term Receivables, in the Notes to Consolidated Financial Statements.

Depreciation, depletion and amortization (DD&A) decreased 12 percent in 2011. The decrease was mostly associated with our E&P segment, reflecting lower production volumes and lower unit-of-production rates related to reserve bookings in 2011.

Impairments decreased 56 percent in 2011, primarily due to the $1,514 million impairment of WRG in 2010. This decrease was partially offset by the impairment of the Trainer Refinery and various North American E&P natural gas properties in 2011. For additional information, see Note 10 Impairments, in the Notes to Consolidated Financial Statements.

Taxes other than income taxes increased 9 percent in 2011, primarily due to higher production taxes as a result of higher crude oil prices and higher excise taxes on petroleum product sales.

Interest and debt expense decreased 18 percent in 2011, primarily due to lower debt levels.

See Note 20 Income Taxes, in the Notes to Consolidated Financial Statements, for information regarding our provision for income taxes and effective tax rate.

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2010 vs. 2009

Sales and other operating revenues increased 27 percent in 2010, while purchased crude oil, natural gas and products increased 33 percent. These increases were primarily due to higher prices for petroleum products, crude oil, natural gas, natural gas liquids and LNG.

Equity in earnings of affiliates increased 24 percent in 2010. The increase primarily resulted from:

- Improved earnings from CPChem primarily due to higher margins in the olefins and polyolefins business line.
- Improved earnings from FCCL Partnership due to higher commodity prices and volumes.
- Improved earnings from Merey Sweeny, L.P. (MSLP) as a result of improved margins and volumes.

These increases were partially offset by a $645 million impairment of our equity investment in NMNG.

Gain on dispositions increased $5,643 million in 2010. The increase was primarily due to the $2,878 million gain realized from the Syncrude sale, the $1,749 million gain on the divestiture of our LUKOIL shares, gains on the disposition of certain E&P assets located in the Lower 48 and Canada, and the gain on sale of our 50 percent interest in CFJ Properties.

Impairments increased $1,245 million in 2010, primarily as a result of the 2010 WRG impairment.

Taxes other than income taxes increased 8 percent during 2010, primarily due to higher production taxes as a result of higher crude oil prices and higher excise taxes on petroleum product sales.

Interest and debt expense decreased 8 percent during 2010, primarily due to lower debt levels.

See Note 20 Income Taxes, in the Notes to Consolidated Financial Statements, for information regarding our provision for income taxes and effective tax rate.

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Segment Results

E&P

	2011	2010	2009
	Millions of Dollars		
Net Income (Loss) Attributable to ConocoPhillips			
Alaska	**$ 1,983**	1,735	1,540
Lower 48	**1,271**	1,033	(37)
United States	**3,254**	2,768	1,503
International	**4,988**	6,430	2,101
	$ 8,242	9,198	3,604
	Dollars Per Unit		
Average Sales Prices			
Crude oil and natural gas liquids (per barrel)			
United States	**$ 91.77**	69.73	53.21
International	**102.68**	74.95	57.40
Total consolidated operations	**97.12**	72.63	55.47
Equity affiliates	**98.60**	74.81	58.23
Total E&P	**97.22**	72.77	55.63
Bitumen (per barrel)			
International	**55.16**	51.10	39.67
Equity affiliates	**63.93**	53.43	45.69
Total E&P	**62.56**	53.06	44.84
Natural gas (per thousand cubic feet)			
United States	**4.01**	4.27	3.50
International	**6.73**	5.60	5.06
Total consolidated operations	**5.64**	5.07	4.40
Equity affiliates	**2.89**	2.79	2.35
Total E&P	**5.34**	4.98	4.37
Average Production Costs Per Barrel of Oil Equivalent			
United States	**$ 9.70**	8.30	7.73
International	**9.70**	7.96	7.72
Total consolidated operations	**9.70**	8.10	7.73
Equity affiliates	**7.85**	8.11	7.68
Total E&P	**9.48**	8.10	7.72
	Millions of Dollars		
Worldwide Exploration Expenses			
General and administrative; geological and geophysical; and lease rentals	**$ 596**	678	576
Leasehold impairment	**161**	241	247
Dry holes	**309**	236	359

	$ 1,066	1,155	1,182

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	2011	2010	2009
	Thousands of Barrels Daily		
Operating Statistics			
Crude oil and natural gas liquids produced			
Alaska	**215**	230	252
Lower 48	**168**	160	166
United States	**383**	390	418
Canada	**38**	38	40
Europe	**175**	211	241
Asia Pacific/Middle East	**111**	140	132
Africa	**40**	79	78
Other areas	**-**	-	4
Total consolidated operations	**747**	858	913
Equity affiliates			
Russia	**29**	52	55
Asia Pacific/Middle East	**23**	3	-
	799	913	968
Synthetic oil produced			
Consolidated operations Canada	**-**	12	23
Bitumen produced			
Consolidated operations Canada	**10**	10	7
Equity affiliates Canada	**57**	49	43
	67	59	50
	Millions of Cubic Feet Daily		
Natural gas produced*			
Alaska	**61**	82	94
Lower 48	**1,556**	1,695	1,927
United States	**1,617**	1,777	2,021
Canada	**928**	984	1,062
Europe	**626**	815	876
Asia Pacific/Middle East	**695**	712	713
Africa	**158**	149	121
Total consolidated operations	**4,024**	4,437	4,793
Equity affiliates			
Asia Pacific/Middle East	**492**	169	84
	4,516	4,606	4,877

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

The E&P segment primarily explores for, produces, transports and markets crude oil, bitumen, natural gas, LNG and natural gas liquids on a worldwide basis. At December 31, 2011, our E&P operations were producing in the United States, Norway, the United Kingdom, Canada, Australia, offshore Timor-Leste in the Timor Sea, Indonesia, China, Vietnam, Libya, Nigeria, Algeria, Qatar and Russia. Total E&P production averaged 1,619,000 BOED in 2011, compared with 1,752,000 BOED in 2010.

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2011 vs. 2010

Earnings from our E&P segment were $8,242 million in 2011, a 10 percent decrease compared with earnings of $9,198 million in 2010. See the Business Environment and Executive Overview section for additional information on industry crude oil and natural gas prices.

U.S. E&P

U.S. E&P earnings were $3,254 million in 2011, an 18 percent increase compared with earnings of $2,768 million in 2010. The increase primarily resulted from higher crude oil and NGL prices, and, to a lesser extent, lower DD&A. These increases were partially offset by higher production taxes, mainly in Alaska, lower sales volumes, higher operating expenses and lower gains from asset sales in the Lower 48.

U.S. E&P production averaged 653,000 BOED in 2011, a decrease of 5 percent from 686,000 BOED in 2010. The decrease was primarily due to field decline and asset dispositions, which was partially offset by new production, mostly from the Lower 48.

International E&P

International E&P earnings were $4,988 million in 2011, a 22 percent decrease compared with earnings of $6,430 million in 2010. Earnings in 2011 included $316 million in additional income tax expense, as a result of legislation enacted in the United Kingdom in July 2011. This additional tax expense consisted of $106 million for the revaluation of deferred tax liabilities and $210 million to reflect the higher tax rates from the effective date of the legislation, March 24, 2011, through December 31, 2011. In 2011, earnings also included impairments of our investment in NMNG and various natural gas properties located in Canada, in addition to a $279 million loss on the dilution of our equity interest in APLNG from 50 percent to 42.5 percent. Earnings in 2010 included gains from the sale of Syncrude and certain Canadian properties and an impairment of NMNG. Excluding the impact from these items, earnings increased in 2011, primarily due to higher prices, a full year of LNG sales from QG3 and lower DD&A. These increases to earnings were partially offset by lower volumes and higher taxes.

International E&P production averaged 966,000 BOED in 2011, a decrease of 9 percent from 1,066,000 BOED in 2010. The decrease primarily resulted from suspended operations in Libya and in Bohai Bay, China, asset dispositions and unplanned downtime. Normal field decline was largely offset by new production.

2010 vs. 2009

Earnings from our E&P segment were $9,198 million in 2010, compared with earnings of $3,604 million in 2009.

U.S. E&P

U.S. E&P earnings increased 84 percent in 2010, from $1,503 million in 2009 to $2,768 million in 2010. The increase was primarily the result of higher prices for crude oil, natural gas and NGLs. Earnings also benefitted from higher gains from asset sales in our Lower 48 portfolio and lower DD&A. These increases were partially offset by lower crude oil and natural gas volumes, higher production taxes, primarily in Alaska, and an unfavorable tax ruling.

U.S. E&P production averaged 686,000 BOED in 2010, a decrease of 9 percent from 755,000 BOED in 2009. The decrease was primarily due to field decline and unplanned downtime, which was somewhat offset by new production.

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International E&P

International E&P earnings were $6,430 million in 2010, compared with $2,101 million in 2009. The increase in 2010 was mostly due to gains from the sale of Syncrude and other assets and higher crude oil, natural gas and LNG prices. These increases were partially offset by the NMNG impairment, lower synthetic oil and natural gas volumes, higher petroleum taxes as a result of higher prices and an $81 million after-tax charge to exploration expenses for project costs resulting from our decision to end participation in the Shah Gas Field Project in Abu Dhabi.

International E&P production averaged 1,066,000 BOED in 2010, a decrease of 3 percent from 1,099,000 BOED in 2009. The decrease was largely due to field decline, the impact of higher prices on production sharing arrangements and the sale of Syncrude. These decreases were partially offset by production from major projects, primarily in China, Canada, Qatar and Australia.

Midstream

	2011	2010	2009
	Millions of Dollars		
Net Income Attributable to ConocoPhillips*	**$ 458**	306	313
**Includes DCP Midstream-related earnings:*	*$ 274*	*191*	*183*
	Dollars Per Barrel		
Average Sales Prices			
U.S. natural gas liquids*			
Consolidated	**$ 57.79**	45.42	33.63
Equity affiliates	**50.64**	41.28	29.80

**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*	**200**	193	187
Natural gas liquids fractionated**	**144**	152	166

**Includes our share of equity affiliates.*

***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 NGLs from the raw gas stream. The remaining residue gas is marketed to electrical utilities, industrial users, and gas marketing companies. Most of the NGLs are fractionated separated into individual components like ethane, butane and propane and marketed as chemical feedstock, fuel or refinery 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 NGL fractionation, trading and marketing businesses, primarily in the United States and Trinidad.

2011 vs. 2010

Earnings from the Midstream segment increased 50 percent in 2011, reflecting higher equity earnings from DCP Midstream and improved results from our other Midstream operations. Both DCP Midstream and our equity affiliate in Trinidad benefited from significantly higher NGL prices, which generally tracked the improved crude oil price environment in 2011. Also benefiting 2011 earnings were higher fees received for NGL fractionation services, reflecting favorably renegotiated contracts. These items were partially offset by higher costs at DCP Midstream, primarily due to higher maintenance and repair costs and increased DD&A.

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2010 vs. 2009

Midstream earnings decreased 2 percent in 2010. Higher NGL prices and, to a lesser extent, improved volumes from our equity affiliate in Trinidad, were more than offset by the absence of the 2009 recognition of an $88 million after-tax benefit, which resulted from a DCP Midstream subsidiary converting subordinated units to common units. In addition, higher operating expenses contributed to the decrease in earnings.

R&M

	$00,000 2011	$00,000 2010	$00,000 2009
		Millions of Dollars	
Net Income (Loss) Attributable to ConocoPhillips			
United States	$ **3,595**	1,022	(192)
International	**156**	(830)	229
	$ **3,751**	192	37
		Dollars Per Gallon	
U.S. Average Wholesale Prices*			
Gasoline	$ **2.94**	2.24	1.84
Distillates	**3.12**	2.30	1.76

**Excludes excise taxes.*

		Thousands of Barrels Daily	
Operating Statistics			
Refining operations*			
United States			
Crude oil capacity**	**1,939**	1,986	1,986
Crude oil processed	**1,757**	1,782	1,731
Capacity utilization (percent)	**91%**	90	87
Refinery production	**1,932**	1,958	1,891
International			
Crude oil capacity**	**426**	671	671
Crude oil processed	**409**	374	495
Capacity utilization (percent)	**96%**	56	74
Refinery production	**419**	383	504
Worldwide			
Crude oil capacity**	**2,365**	2,657	2,657
Crude oil processed	**2,166**	2,156	2,226
Capacity utilization (percent)	**92%**	81	84
Refinery production	**2,351**	2,341	2,395
Petroleum products sales volumes			
United States			
Gasoline	**1,129**	1,120	1,130

Distillates	**884**	873	858
Other products	**401**	400	367
	2,414	2,393	2,355
International	**714**	647	619
	3,128	3,040	2,974

**Includes our share of equity affiliates.*

***Weighted-average crude oil capacity for the periods.*

Our R&M segment refines crude oil and other feedstocks into petroleum products (such as gasoline, distillates and aviation fuels); buys, sells and transports crude oil; and buys, transports, distributes and markets petroleum products. R&M has operations mainly in the United States, Europe and Asia.

2011 vs. 2010

R&M reported earnings of $3,751 million in 2011, compared with earnings of $192 million in 2010. See the Business Environment and Executive Overview section for additional information on industry refining margins.

U.S. R&M

Earnings from U.S. R&M were $3,595 million in 2011, compared with earnings of $1,022 million in 2010. The increase in earnings primarily resulted from significantly higher refining margins and gains from asset sales. In 2011, gains from asset sales of $1,577 million after-tax mainly resulted from the sales of Seaway Products Pipeline Company and our equity investments in Seaway Crude Pipeline Company and Colonial Pipeline Company, while 2010 included the $113 million after-tax gain on sale of our 50 percent interest in CFJ Properties. These increases were partially offset by the $303 million after-tax impairment and warehouse inventory write-down associated with our Trainer Refinery in 2011.

Our U.S. refining crude oil capacity utilization rate was 91 percent in 2011, compared with 90 percent in 2010. The increase mainly resulted from lower turnaround activity, partially offset by higher planned and unplanned downtime.

International R&M

International R&M reported earnings of $156 million in 2011, compared with a loss of $830 million in 2010. The increase in earnings was mostly due to the absence of the 2010 WRG impairment, in addition to higher refining volumes and foreign currency gains in 2011. These increases were partially offset by lower refining margins and the $86 million after-tax loss on sale of WRG and related warehouse inventory write-downs in 2011.

Our international refining crude oil capacity utilization rate was 96 percent in 2011, compared with 56 percent in 2010. The increase primarily resulted from the removal of WRG from our refining capacities effective January 1, 2011, and lower turnaround activity.

2010 vs. 2009

R&M reported earnings of $192 million in 2010, compared with earnings of $37 million in 2009.

U.S. R&M

Earnings from U.S. R&M were $1,022 million in 2010, compared with a loss of $192 million in 2009. The increase in 2010 primarily resulted from significantly higher refining margins and the gain on sale of CFJ. Higher refining and marketing volumes also contributed to the improvement in earnings.

Our U.S. refining crude oil capacity utilization rate was 90 percent in 2010, compared with 87 percent in 2009. The increase in 2010 was largely due to lower turnaround activity, lower run reductions due to market conditions, and less unplanned downtime.

International R&M

International R&M reported a loss of $830 million in 2010, compared with earnings of $229 million in 2009. The loss in 2010 mainly resulted from the WRG impairment and a $29 million after-tax impairment resulting from our decision to end participation in the Yanbu Refinery Project. Excluding these impairments, earnings were improved due to higher refining margins, partially offset by foreign currency losses.

Our international refining crude oil capacity utilization rate was 56 percent in 2010, compared with 74 percent in 2009. The 2010 rate primarily reflected run reductions at WRG in response to market conditions.

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LUKOIL Investment

	$00,0000		$00,0000	$00,0000
	Millions of Dollars			
		2011	2010	2009
Net Income Attributable to ConocoPhillips	$	**239**	2,503	1,219
Operating Statistics				
Crude oil production (thousands of barrels daily)		-	284	388
Natural gas production (millions of cubic feet daily)		-	254	295
Refinery crude oil processed (thousands of barrels daily)		-	189	240

This segment represents our former investment in the ordinary shares of OAO LUKOIL, an international, integrated oil and gas company headquartered in Russia. We sold our remaining interest in LUKOIL in the first quarter of 2011.

2011 vs. 2010

Earnings in 2011 primarily represented the realized gain on remaining share sales. Earnings in 2010 primarily reflected earnings from the equity investment in LUKOIL we held at the time, in addition to gains on the partial sale of our LUKOIL investment.

2010 vs. 2009

LUKOIL segment earnings increased $1,284 million in 2010, which primarily resulted from the $1,251 million after-tax gain on our LUKOIL shares sold during 2010.

Chemicals

	$00,0000		$00,0000	$00,0000
	Millions of Dollars			
		2011	2010	2009
Net Income Attributable to ConocoPhillips	$	**745**	498	248

The Chemicals segment consists of our 50 percent interest in 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.

2011 vs. 2010

Earnings from the Chemicals segment increased 50 percent in 2011, primarily due to higher margins, volumes and equity earnings in the olefins and polyolefins business line. The specialties, aromatics and styrenics business line also contributed to the increase in earnings due to higher margins.

2010 vs. 2009

Earnings from the Chemicals segment increased $250 million in 2010, primarily due to substantially higher margins in the olefins and polyolefins business line and, to a lesser extent, improved margins from the specialties, aromatics and styrenics business line. Higher operating costs partially offset these increases.

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Emerging Businesses

		$00,0000	$00,0000	$00,0000
			Millions of Dollars	
		2011	2010	2009
Net Income (Loss) Attributable to ConocoPhillips				
Power	**$**	**115**	49	105
Other		**(141)**	(108)	(102)
	$	**(26)**	(59)	3

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, refining, alternative energy, biofuels, and the environment.

2011 vs. 2010

The Emerging Businesses segment reported a loss of $26 million in 2011, compared with a loss of $59 million in 2010. The increase in Power earnings was primarily due to the absence of 2010 impairment charges related to a U.S. cogeneration plant, which was sold in December 2010, combined with higher international power generation results. Higher technology development expenses contributed to the increase in Other losses in 2011.

2010 vs. 2009

The Emerging Businesses segment reported a loss of $59 million in 2010, compared with earnings of $3 million in 2009. The decrease in Power earnings was mainly due to higher operating costs and lower margins in international power generation, in addition to the impairment charges and loss on sale of the U.S. cogeneration plant. Higher technology development expenses contributed to the increase in Other losses in 2010.

Corporate and Other

		$00,0000	$00,0000	$00,0000
			Millions of Dollars	
		2011	2010	2009
Net Loss Attributable to ConocoPhillips				
Net interest	**$**	**(667)**	(965)	(851)
Corporate general and administrative expenses		**(199)**	(209)	(108)
Separation costs		**(25)**	-	-
Other		**(82)**	(106)	(51)
	$	**(973)**	(1,280)	(1,010)

2011 vs. 2010

Net interest consists of interest and financing expense, net of interest income and capitalized interest, as well as premiums incurred on the early retirement of debt. Net interest decreased 31 percent in 2011, mostly due to lower interest expense, which resulted from lower debt levels; the absence of a $114 million after-tax premium on early debt retirement, which occurred in 2010; and slightly higher interest income.

Separation costs consist of expenses incurred for the planned separation of our downstream businesses into a stand-alone, publicly traded company, Phillips 66. Expenses incurred in 2011 primarily included legal, accounting and information systems costs.

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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. Changes in the Other category primarily resulted from foreign currency transaction gains and lower environmental costs, partially offset by a $20 million after-tax property impairment.

2010 vs. 2009

Net interest increased 13 percent in 2010, mostly due to the $114 million after-tax premium on early debt retirement and a lower effective tax rate. These increases were partially offset by lower interest expense due to lower debt levels.

Corporate general and administrative expenses increased $101 million in 2010, primarily as a result of costs related to compensation and benefit plans.

Changes in the Other category primarily reflected foreign currency transaction losses.

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CAPITAL RESOURCES AND LIQUIDITY

Financial Indicators

	Millions of Dollars Except as Indicated		
	2011	2010	2009
Net cash provided by operating activities	**$ 19,646**	17,045	12,479
Short-term debt	**1,013**	936	1,728
Total debt	**22,623**	23,592	28,653
Total equity	**65,734**	69,109	62,613
Percent of total debt to capital*	**26%**	25	31
Percent of floating-rate debt to total debt**	**10%**	10	9

**Capital includes total debt and total equity.*

***Includes effect of interest rate swaps.*

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 2011, we received $4,820 million in proceeds from asset sales. During 2011, the primary uses of our available cash were $13,266 million to support our ongoing capital expenditures and investments program; $11,123 million to repurchase common stock; $3,632 million to pay dividends on our common stock; and $961 million to repay debt. During 2011, cash and cash equivalents decreased by $3,674 million to $5,780 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 statement to support our short- and long-term liquidity requirements. 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 2011, cash of $19,646 million was provided by operating activities, a 15 percent increase from cash from operations of $17,045 million in 2010. The increase was primarily due to higher commodity prices in our E&P segment and higher U.S. refining margins in our R&M segment.

During 2010, cash flow from operations increased $4,566 million, compared with 2009. The increase was primarily due to significantly higher crude oil prices in our E&P segment and higher refining margins in our R&M segment.

While the stability of our cash flows from operating activities benefits from geographic diversity, our short- and long-term operating cash flows are highly dependent upon prices for crude oil, bitumen, natural gas, LNG and natural gas liquids, as well as refining and marketing margins. Crude oil prices increased in 2009, 2010 and 2011, although natural gas prices remained weak. Global refining margins were under pressure during 2009 and 2010. Domestic refining margins significantly improved during the first three quarters of 2011, followed by a sharp decline in the fourth quarter of 2011. Prices and margins in our industry are typically volatile, and 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.

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The level of our production volumes of crude oil, bitumen, 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 their timely and cost-effective development. 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 E&P production for 2011 averaged 1.62 million BOED. 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 effects of price changes on production sharing and variable-royalty contracts; timing of project startups and major turnarounds; and weather-related disruptions. Our production in 2012, excluding the impact of any additional dispositions, is expected to be approximately 1.6 million BOED. We continue to evaluate various properties as potential candidates for our disposition program. The makeup and timing of our disposition program will also impact 2012 and future years production levels.

To maintain or grow our production volumes, we must continue to add to our proved reserve base. Our total reserve replacement in 2011 was 112 percent, including 117 percent from consolidated operations. Excluding the impact of acquisitions and dispositions, the reserve replacement was 120 percent of 2011 production. Over the five-year period ended December 31, 2011, our reserve replacement was 30 percent (including 64 percent from consolidated operations) reflecting the disposition of our interest in LUKOIL, the expropriation of our assets in Venezuela and the impact of our asset disposition program. Excluding these items and acquisitions, our five-year reserve replacement was 102 percent. The total reserve replacement amount above is 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. For additional information about our proved reserves, including both developed and undeveloped reserves, see 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; therefore, each year reserves may be revised upward or downward due to the impact of changes in commodity prices or as more technical data becomes available on reservoirs. In 2011, 2010 and 2009, revisions increased reserves. It is not possible to reliably predict how revisions will impact reserve quantities in the future.

In our R&M segment, 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, market conditions, 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.

Asset Sales

Proceeds from asset sales in 2011 were $4.8 billion, compared with $15.4 billion in 2010. The 2011 proceeds from asset sales included $2.0 billion from the sale of our ownership interests in Colonial Pipeline Company and Seaway Crude Pipeline Company and $1.2 billion from the sale of our remaining interest in LUKOIL. Other asset sales primarily included mature North American natural gas assets and a products pipeline. We plan to raise an additional $5 billion to $10 billion from asset sales in 2012.

Commercial Paper and Credit Facilities

In August 2011, we increased our revolving credit facilities from $7.85 billion to $8.0 billion by replacing our $7.35 billion revolving credit facility with a $7.5 billion facility expiring in August 2016. The terms of the new revolving credit facility are similar to the terms of the replaced facility. We also have a $500 million facility expiring in July 2012. Our revolving credit facilities may be used as direct bank borrowings, as support for issuances of letters of credit totaling up to $750 million, or as support for our commercial paper programs. 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.

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.

Our primary funding source for short-term working capital needs is the ConocoPhillips $6.35 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 QG3 Project. At December 31, 2011 and 2010, we had no direct borrowings under the revolving credit facilities, but $40 million in letters of credit had been issued at both periods. In addition, under the two ConocoPhillips commercial paper programs, $1,128 million of commercial paper was outstanding at December 31, 2011, compared with $1,182 million at December 31, 2010. Since we had $1,128 million of commercial paper outstanding and had issued $40 million of letters of credit, we had access to $6.8 billion in borrowing capacity under our revolving credit facilities at December 31, 2011.

Our senior long-term debt is rated A1 by Moody s Investors Service and A by both Standard and Poor s Rating Service and by Fitch. 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. If our credit rating were to deteriorate to a level prohibiting us from accessing the commercial paper market, we would still be able to access funds under our $7.5 billion and $500 million revolving credit facilities.

Shelf Registration

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

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.

We own a 30 percent interest in QG3, 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. QG3 secured project financing of $4 billion in 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. On December 15, 2011, QG3 achieved financial completion and all project loan facilities became nonrecourse to the project participants. At December 31, 2011, QG3 had approximately $3.9 billion outstanding under all the loan facilities, including $1.2 billion owed to ConocoPhillips.

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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, 2011, was $22.6 billion, a decrease of $1.0 billion during 2011, and our debt-to-capital ratio was 26 percent at year-end 2011, versus 25 percent at the end of 2010. The slight increase in the debt-to-capital ratio was due to a decrease in total equity resulting from the share repurchase programs in 2011, partially offset by the debt reduction. Our debt-to-capital ratio target range is 20 to 25 percent.

In 2007, we closed on a business venture with Cenovus Energy Inc. As part of this transaction, we are obligated to contribute $7.5 billion, plus accrued interest, over a 10-year period that began in 2007, to the upstream business venture, FCCL, formed as a result of the transaction. 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 $732 million was short-term and was included in the Accounts payable related parties line on our December 31, 2011, consolidated balance sheet. The principal portion of these payments, which totaled $695 million in 2011, is 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 payment is reflected as a capital contribution and is included in the Capital expenditures and investments line on our consolidated statement of cash flows.

During 2011, WRB Refining LP repaid $550 million of loan financing to ConocoPhillips that had been provided to assist WRB in meeting its operating and capital spending requirements. No outstanding balance remained at December 31, 2011.

In February 2012, we announced a dividend of 66 cents per share. The dividend is payable March 1, 2012, to stockholders of record at the close of business February 21, 2012.

On March 24, 2010, our Board of Directors authorized the purchase of up to $5 billion of our common stock through 2011. Repurchase of shares under this authorization was completed in the first quarter of 2011. On February 11, 2011, the Board authorized the additional purchase of up to $10 billion of our common stock over the subsequent two years. Repurchase of shares under this authorization was completed in the fourth quarter of 2011. Under both programs, repurchases totaled 220 million shares at a cost of $15 billion through December 31, 2011. On December 2, 2011, our Board of Directors authorized the purchase of up to an additional $10 billion of our common stock over the subsequent two years.

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Contractual Obligations

The following table summarizes our aggregate contractual fixed and variable obligations as of December 31, 2011:

		Millions of Dollars Payments Due by Period				
		Total	Up to 1 Year	Years 2-3	Years 4-5	After 5 Years
Debt obligations (a)	$	22,592	1,005	2,799	3,933	14,855
Capital lease obligations		31	8	3	2	18
Total debt		22,623	1,013	2,802	3,935	14,873
Interest on debt and other obligations		19,798	1,319	2,567	2,227	13,685
Operating lease obligations		2,761	767	901	502	591
Purchase obligations (b)		145,114	60,105	13,142	8,101	63,766
Joint venture acquisition obligation (c)		4,314	732	1,586	1,762	234
Other long-term liabilities (d)						
Asset retirement obligations		8,920	387	668	505	7,360
Accrued environmental costs		922	126	147	97	552
Unrecognized tax benefits (e)		153	153	(e)	(e)	(e)
Total	$	204,605	64,602	21,813	17,129	101,061

(a) Includes $449 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, 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 $71,737 million. In addition, $50,741 million are product purchases from CPChem, mostly for natural gas and natural gas liquids over the remaining term of 88 years, and Excel Paralubes, for base oil over the remaining initial term of 14 years.

Purchase obligations of $17,044 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 a six-year period to the FCCL upstream joint venture with Cenovus.

(d) Does not include: Pensions for the 2012 through 2016 time period, we expect to contribute an average of $490 million per year to our qualified and nonqualified pension and postretirement benefit plans in the United States and an average of $250 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 $690 million for 2012 and then approximately $445 million per year for the remaining four years. Our required minimum funding in 2012 is expected to be $530 million in the United States and $220 million outside the United States.

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(e) Excludes unrecognized tax benefits of $918 million because the ultimate disposition and timing of any payments to be made with regard to such amounts 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

		$00,00000	$00,00000	$00,00000	$00,00000
			Millions of Dollars		
		2012 Budget	**2011**	2010	2009
Capital Expenditures and Investments					
E&P					
United States Alaska	$	900	**775**	730	810
United States Lower 48		4,800	**3,880**	1,855	2,664
International		7,600	**7,350**	5,908	5,425
		13,300	**12,005**	8,493	8,899
Midstream		-	**17**	3	5
R&M					
United States		1,000	**768**	790	1,299
International		200	**226**	266	427
		1,200	**994**	1,056	1,726
LUKOIL Investment		-	**-**	-	-
Chemicals		-	**-**	-	-
Emerging Businesses		100	**30**	27	97
Corporate and Other		200	**220**	182	134
	$	14,800	**13,266**	9,761	10,861
United States	$	7,000	**5,679**	3,576	4,921
International		7,800	**7,587**	6,185	5,940
	$	14,800	**13,266**	9,761	10,861

Our capital expenditures and investments for the three-year period ending December 31, 2011, totaled $33.9 billion, with 87 percent allocated to our E&P segment.

Our capital expenditures and investments budget for 2012 is $14.8 billion. Included in this amount is approximately $0.4 billion in capitalized interest. We plan to direct 90 percent of the capital expenditures and investments budget to E&P and 8 percent to R&M. With the addition of principal contributions related to funding our portion of the FCCL business venture, our total capital program for 2012 is approximately $15.5 billion.

E&P

Capital expenditures and investments for E&P during the three-year period ended December 31, 2011, totaled $29.4 billion. The expenditures over this period supported key exploration and development projects including:

Oil, natural gas liquids and natural gas developments in the Lower 48, including Texas, New Mexico, North Dakota, Oklahoma, Montana, Colorado, Wyoming and offshore in the Gulf of Mexico.
Advancement of coalbed methane (CBM) projects associated with the APLNG joint venture in Australia.
Oil sands projects and ongoing natural gas projects in Canada.
Alaska activities related to development drilling in the Greater Kuparuk Area, the Greater Prudhoe Area, the Western North Slope and the Cook Inlet Area.

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- Development drilling and facilities projects in the Norwegian sector of the North Sea, including the Greater Ekofisk Area, Alvheim and Statfjord, and Heidrun in the Norwegian Sea.
- The Peng Lai 19-3 development in China s Bohai Bay.
- The Kashagan Field and satellite prospects in the Caspian Sea offshore Kazakhstan.
- In the U.K. sector of the North Sea, the development of the Jasmine discovery in the J-Block Area, the development of Clair Ridge, development drilling on Clair and in the southern and central North Sea.
- The North Belut Field, as well as other projects in offshore Block B and onshore South Sumatra in Indonesia.
- The QG3 Project, an integrated project to produce and liquefy natural gas from Qatar s North Field.
- The Gumusut-Kakap development offshore Sabah, Malaysia.
- Exploration activities in Australia s Browse Basin, North American shale plays, Canadian oil sands projects, deepwater Gulf of Mexico, Alaska, U.K. and Norwegian sectors of the North Sea, Kazakhstan and Indonesia.
- The El Merk Project, comprised of wells, gathering lines and a shared central processing facility to develop the EMK Field Unit in Algeria.

2012 CAPITAL EXPENDITURES AND INVESTMENTS BUDGET

E&P s 2012 capital expenditures and investments budget is $13.3 billion, 11 percent higher than actual expenditures in 2011. Forty-three percent of E&P s 2012 capital expenditures and investments budget is planned for the United States.

Capital spending for our Alaskan operations is expected to be directed toward the Prudhoe Bay and Kuparuk fields, as well as the Alpine Field and satellites on the Western North Slope.

In the Lower 48, we expect to focus capital expenditures and investments on development of liquids-rich areas, such as the Eagle Ford Trend, and the Williston and Permian basins. We also expect to direct capital spending towards exploration and appraisal activities in the Eagle Ford shale formation, as well as recently acquired acreage in the Avalon, Wolfcamp, and Niobrara areas. In addition, we plan to appraise our recent deepwater Gulf of Mexico discoveries.

E&P is directing $7.6 billion of its 2012 capital expenditures and investments budget to international projects. Funds in 2012 are expected to be directed to developing major long-term projects including:

- Liquids opportunities in the western Canada basins and Canadian oil sands projects.
- Further development of CBM projects associated with the APLNG joint venture in Australia.
- Elsewhere in the Asia Pacific/Middle East Region, continued development of Bohai Bay in China, new fields offshore Malaysia, and offshore Block B and onshore South Sumatra in Indonesia.
- In the North Sea, the Greater Ekofisk Area, development of the Jasmine discovery in the J-Block Area, development of Clair Ridge and the Britannia Long-Term Compression Project.
- The Kashagan Field in the Caspian Sea.
- Onshore developments in Nigeria, Algeria and Libya.
- Exploration and appraisal activities in Canadian shale plays and oil sands projects, Australia s offshore Browse Basin and onshore Canning Basin, deepwater Angola, Kazakhstan s Block N, offshore Indonesia, Nigeria and the North Sea.

For information on proved undeveloped reserves and the associated costs to develop these reserves, see the Oil and Gas Operations section.

R&M

Capital spending for R&M during the three-year period ended December 31, 2011, was primarily for air emission reduction and clean fuels projects to meet new environmental standards, refinery upgrade projects to improve product yields and increase heavy crude oil processing capability, improving the operating integrity of key processing units, as well as for safety projects. During this three-year period, R&M capital spending was $3.8 billion, which represented 11 percent of our total capital expenditures and investments.

Key projects during the three-year period included:

- Installation of a 20,000-barrel-per-day hydrocracker at the Rodeo facility of our San Francisco Refinery.
- Installation of a 225-ton-per-day sulfur plant at the Sweeny Refinery.
- Installation of facilities to reduce emissions from the Fluid Catalytic Crackers at the Alliance and Sweeny refineries.
- Installation of facilities to reduce nitrous oxide emissions from the crude furnace and installation of a new vacuum furnace at the Bayway Refinery.
- Completion of gasoline benzene reduction projects at the Alliance and Ponca City refineries.

Major construction activities in progress include:

- Installation, revamp and expansion of equipment at the Bayway Refinery to enable production of low benzene gasoline.
- U.S. programs aimed at air emission reductions.

2012 CAPITAL EXPENDITURES AND INVESTMENTS BUDGET

R&M s 2012 capital expenditures and investments budget is $1.2 billion, a 21 percent increase from actual spending in 2011, with about $1.0 billion targeted in the United States and $0.2 billion internationally. These funds will be used primarily for projects related to sustaining and improving the existing business with a focus on safety, regulatory compliance, efficiency and reliability.

Emerging Businesses

Capital spending for Emerging Businesses during the three-year period ended December 31, 2011, was primarily for an expansion and other capital improvements at the Immingham combined heat and power cogeneration plant near our Humber Refinery in the United Kingdom.

Contingencies

A number of lawsuits involving a variety of claims have been made against ConocoPhillips that arise in the ordinary course of business. We also may be required 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 active and inactive sites. We regularly assess the need for accounting recognition or disclosure of these contingencies. In the case of all known contingencies (other than those related to income taxes), 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 use 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. As we learn new facts concerning contingencies, we reassess our position both with respect to accrued liabilities and other potential exposures. Estimates 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

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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.

Legal and Tax Matters

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 that have been scheduled for trial and/or mediation. 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 regularly assesses the adequacy of current accruals and determines if adjustment of existing accruals, or establishment of new accruals, are required. See Note 20 Income Taxes, in the Notes to Consolidated Financial Statements, for additional information about income-tax-related contingencies.

Environmental

We are subject to the same numerous international, federal, state and local environmental laws and regulations as other companies in our industry. 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.

An example in the fuels area is the Energy Policy Act of 2005, which imposed obligations to provide increasing volumes of renewable fuels in transportation motor fuels through 2012. These obligations were changed with the enactment of the Energy Independence and Security Act of 2007. The 2007 law requires fuel producers and importers to provide additional renewable fuels for transportation motor fuels that include a mix of various types to be included through 2022. We have met the increased requirements to date while establishing implementation, operating and capital strategies, along with advanced technology development, to address projected future requirements.

Another example is the use of hydraulic fracturing, an essential completion technique that facilitates production of oil and natural gas that is otherwise trapped in lower permeability rock formations. A range of local, state, federal or national laws and regulations currently govern hydraulic fracturing operations. Although hydraulic fracturing has been conducted for many decades, a number of new laws, regulations and permitting requirements are under consideration by the U.S. Environmental Protection Agency (EPA), the U.S. Department of the Interior, and others which could result in increased costs, operating restrictions, operational delays and/or limit the ability to develop oil and natural gas resources. Governmental restrictions on hydraulic fracturing could impact the overall profitability or viability of certain of our oil and natural gas investments. We have adopted operating principles that incorporate established industry standards designed to meet or exceed government requirements. Our practices continually evolve as technology improves and regulations change.

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. We anticipate increased 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 occasionally 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, 2010, we reported we had been notified of potential liability under CERCLA and comparable state laws at 73 sites around the United States. At December 31, 2011, we had been notified of 8 new sites, settled 5 sites and closed 2 sites, bringing the number to 74 unresolved sites with 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 $1,039 million in 2011 and are expected to be about $1,100 million per year in 2012 and 2013. Capitalized environmental costs were $573 million in 2011 and are expected to be about $875 million per year in 2012 and 2013.

Accrued liabilities for remediation activities 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.

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, 2011, our balance sheet included total accrued environmental costs of $922 million, compared with $994 million at December 31, 2010. 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 concerns 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 it is not possible to accurately estimate either a timetable for implementation or our future compliance costs relating to implementation, such laws, if enacted, could have a material impact on our results of operations and financial condition. Examples of legislation or precursors for possible regulation that do 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.

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- California s Global Warming Solutions Act, which requires the California Air Resources Board to develop regulations and market mechanisms that will target reduction of California s GHG 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 EPA has the authority to regulate carbon dioxide as an air pollutant under the Federal Clean Air Act.
- The EPA s announcement on March 29, 2010 (published as Interpretation of Regulations that Determine Pollutants Covered by Clean Air Act Permitting Programs, 75 Fed. Reg. 17004 (April 2, 2010)), and the EPA s and U.S. Department of Transportation s joint promulgation of a Final Rule on April 1, 2010, that triggers regulation of GHGs under the Clean Air Act, may trigger more climate-based claims for damages, and may result in longer agency review time for development projects.
- Carbon taxes in certain jurisdictions.
- Cap and trade programs in certain jurisdictions, including the Australian Clean Energy Legislation which is scheduled to take effect July 2012.

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, some additional form of regulation may be forthcoming in the future at the federal and state levels with respect to GHG emissions. Such regulation could take any of several forms that may result in the creation of additional costs in the form of taxes, the restriction of output, investments of capital to maintain compliance with laws and regulations, or required acquisition or trading of emission allowances. We are working to continuously improve operational and energy efficiency through resource and energy conservation throughout our operations.

Compliance with changes in laws and regulations that create a GHG emission trading scheme or GHG reduction policies could significantly increase our costs, reduce demand for fossil energy derived products, impact the cost and availability of capital and increase our exposure to litigation. Such laws and regulations could also increase demand for less carbon intensive energy sources, including natural gas. The ultimate impact on our financial performance, either positive or negative, will depend on a number of factors, including but not limited to:

- Whether and to what extent legislation is enacted.
- The nature of the legislation (such as a cap and trade system or a tax on emissions).
- The GHG reductions required.
- The price and availability of offsets.
- The amount and allocation of allowances.
- Technological and scientific developments leading to new products or services.
- Any potential significant physical effects of climate change (such as increased severe weather events, changes in sea levels and changes in temperature).
- Whether, and the extent to which, increased compliance costs are ultimately reflected in the prices of our products and services.

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.

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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 there is a reasonable likelihood 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 2011, 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 $1,880 million and the accumulated impairment reserve was $487 million. The weighted-average judgmental percentage probability of ultimate failure was approximately 47 percent, and the weighted-average amortization period was approximately four years. If that judgmental percentage were to be raised by 5 percent across all calculations, pretax leasehold impairment expense in 2012 would increase by approximately $22 million. The remaining $5,966 million of gross capitalized unproved property costs at year-end 2011 consisted of individually significant leaseholds, mineral rights held in perpetuity by title ownership, exploratory wells currently drilling, suspended exploratory wells, and capitalized interest. 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 $3.0 billion is concentrated in 10 major development areas. One of these major assets totaling $97 million is expected to move to proved properties in 2012.

Exploratory Costs

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

If 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

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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 we are actively pursuing such approvals and permits, and believe 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. 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.

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 2011, total suspended well costs were $1,037 million, compared with $1,013 million at year-end 2010. For additional information on suspended wells, including an aging analysis, see Note 8 Suspended Wells, in the Notes to Consolidated Financial Statements.

Proved Reserves

Engineering estimates of the quantities of proved reserves are inherently imprecise and represent only approximate amounts because of the judgments involved in developing such information. Reserve estimates are based on geological and engineering assessments of in-place hydrocarbon volumes, the production plan, historical extraction recovery and processing yield factors, installed plant operating capacity and approved operating 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 consistent with these authoritative guidelines. We have trained and experienced internal engineering personnel who estimate our proved reserves held by consolidated companies, as well as our share of equity affiliates.

Proved reserve estimates are adjusted annually in the fourth quarter and during the year if significant changes occur, and take into account recent production and subsurface information about each field. Also, as required by current authoritative guidelines, the estimated future date when a field will be permanently shut down for economic reasons is based on 12-month average prices and year-end costs. 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 commodity prices; 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 developed reserves also is important to the income statement because the proved developed reserve estimate for a field serves as the denominator in the unit-of-production calculation of DD&A of the capitalized costs for that asset. At year-end 2011, the net book value of productive E&P properties, plants and equipment (PP&E) subject to a unit-of-production calculation was approximately $57 billion and the DD&A

recorded on these assets in 2011 was approximately $6.6 billion. The estimated proved developed reserves for our consolidated operations were 5.2 billion BOE at the end of 2010 and 5.1 billion BOE at the end of 2011. If the estimates of proved reserves used in the unit-of-production calculations had been lower by 5 percent across all calculations, pretax DD&A in 2011 would have increased by an estimated $347 million.

Impairments

Long-lived assets used in operations are assessed for impairment whenever changes in facts and circumstances indicate a possible significant deterioration in future cash flows expected to be generated by an asset group and annually in the fourth quarter following updates to corporate planning assumptions. 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, or at an entire complex level for downstream assets. Because there usually is a lack of quoted market prices for long-lived assets, the fair value of impaired assets is typically determined based on the present values of expected future cash flows using discount rates believed to be consistent with those used by principal market participants, 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, commodity prices, operating costs, refining margins and capital project decisions, 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 and annually following updates to corporate planning assumptions. 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 our ability and intention to retain our 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 believed to be consistent with those used by principal market participants, plus market analysis of comparable assets owned by the investee, if appropriate. Differing assumptions could affect the timing and the amount of an impairment of an investment in any period.

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 plugging and abandonment of wells, 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 into PP&E 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, regulatory and other compliance considerations, expenditure timing, and other inputs into valuation of the obligation, including discount and inflation rates, are also subject to change.

Normally, changes in asset removal obligations are reflected in the income statement as increases or decreases to DD&A over the remaining life of the assets. However, for assets at or nearing the end of their operations, as well as previously sold assets for which we retained the asset removal obligation, an increase in the asset removal obligation can result in an immediate charge to earnings, because any increase in PP&E due to the increased obligation would immediately be subject to impairment, due to the low fair value of these properties.

In addition to asset removal obligations, 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 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.

Business Acquisitions

Assets Acquired and Liabilities Assumed

Accounting for the acquisition of a business requires the recognition of the consideration paid, as well as the various assets and liabilities of the acquired business. For most assets and liabilities, the asset or liability is recorded at its estimated fair value. The most difficult estimates of individual fair values are those involving PP&E 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 finalize these fair value determinations.

Intangible Assets and Goodwill

At December 31, 2011, we had $701 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.

At December 31, 2011, we had $3,332 million of goodwill on our balance sheet, all of which was attributable to the Worldwide R&M reporting unit. See Note 9 Goodwill and Intangibles, in the Notes to Consolidated Financial Statements, for additional information on intangibles and goodwill.

Projected Benefit Obligations

Determination of the projected benefit obligations for our defined benefit pension and postretirement plans are important to the recorded amounts for such obligations on the balance sheet and to the amount of benefit expense in the income statement. 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 the plan. 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 assumption would increase annual benefit expense by $130 million, while a 1 percent decrease in the return on plan assets assumption would increase annual benefit expense by $70 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.

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OUTLOOK

Planned Separation of Downstream Businesses

On July 14, 2011, we announced approval by our Board of Directors to pursue the separation of our refining, marketing and transportation businesses into a stand-alone, publicly traded corporation via a tax-free distribution. The new downstream company, named Phillips 66, will be headquartered in Houston, Texas. In addition to the refining, marketing and transportation businesses, we expect Phillips 66 will also include most of our Midstream segment, our Chemicals segment, as well as our power generation and certain technology operations included in our Emerging Businesses segment, to create an integrated downstream company. The separation is to be accomplished by the pro rata distribution of one share of Phillips 66 stock for every two shares of ConocoPhillips stock held by ConocoPhillips shareholders on the record date for the share distribution.

In October 2011, we requested a private letter ruling from the U.S. Internal Revenue Service, which is expected to confirm the distribution will qualify as a tax-free reorganization for U.S. federal income tax purposes. In addition, we filed the initial Phillips 66 Form 10 registration statement with the SEC on November 14, 2011, and an amendment on January 3, 2012.

The separation is subject to market conditions, customary regulatory approvals, the receipt of an affirmative Internal Revenue Service private letter ruling and final Board approval, and is expected to be completed in the second quarter of 2012.

As part of the separation, we expect to receive a cash distribution from Phillips 66. These funds will primarily be used to repay debt, with the balance directed to share repurchases and dividends. In conjunction with the separation, we expect to incur one-time legal, information technology, audit, advisor, and deferred and cash tax costs, resulting in an estimated pre-separation earnings impact of approximately $150 million after-tax, of which $25 million was incurred in 2011.

China Bohai Bay

On July 13, 2011, the State Oceanic Administration (SOA) in the People s Republic of China instructed us to suspend production from the Peng Lai 19-3 Field Platforms B and C, as a result of two separate seepage incidents which occurred near the platforms. On September 2, 2011, the SOA ordered us to halt operations at the Peng Lai 19-3 Field, pending additional cleanup efforts and reservoir depressurization activities to ensure any residual seepage had stopped. The incidents resulted in a total release of approximately 700 barrels of oil into Bohai Bay and approximately 2,600 barrels of mineral oil-based drilling mud onto the seafloor. The mineral oil-based drilling mud was recovered and cleaned up from the seafloor. The sources of the seeps have been sealed and containment devices deployed as a preventative measure to capture any residue.

The SOA also required implementation of preventative measures to avoid recurrence, in addition to the filing of an updated environmental impact assessment and development plan for approval. A revised development plan was submitted to China s National Development and Reform Commission in November 2011 and is currently under review. A revised environmental impact assessment was submitted to the SOA in February 2012.

The approved depressurization plan, combined with limited development and field optimization, reduced 2011 average daily net production from the field by 14,000 barrels of oil per day, compared to 2010 production levels. Future impacts on our business are not known at this time.

In January 2012, we and the China National Offshore Oil Corp. (CNOOC) announced an agreement with China s Ministry of Agriculture to resolve fishery-related issues in connection with the seepage incidents. Under this agreement, approximately $160 million will be paid as compensation to settle private claims of potentially affected fishermen in relevant Bohai Bay communities, and public claims for alleged fishery damage. We hold a 49 percent ownership interest in the Peng Lai fields. The agreement fulfills the objectives of the compensation fund we announced in September 2011. As part of this agreement, we have also designated approximately $16 million of our previously announced environmental fund to be used to improve fishery resources and for related projects.

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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, budget, continu could, intend, may, plan, potential, predict, seek, should, will, would, expect, objective, projection, forecast, goa target and similar expressions.

We based the forward-looking statements 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 as they involve assumptions that, while made in good faith, may prove to be incorrect, and involve risks and uncertainties 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, bitumen, natural gas, LNG and natural gas liquids prices, refining and marketing margins and margins for our chemicals business.
- Potential failures 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 reserves and 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 chemicals products.
- Lack of, or disruptions in, adequate and reliable transportation for our crude oil, natural gas, natural gas liquids, bitumen, LNG and refined products.
- Inability to timely obtain or maintain permits, including those necessary for drilling and/or development projects, 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, terrorism or cyber attacks.
- 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, bitumen, natural gas, LNG, 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.
- Delays in, or our inability to implement, our asset disposition plan.
- Inability to obtain economical financing for projects, construction or modification of facilities and general corporate purposes.

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- The operation and financing of our joint ventures.
- The effect of restructuring or reorganization of business components.
- The effect of the separation of our downstream businesses.
- The factors generally described 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 currency 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 capture 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 establishes the 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 also reports to the Chief Executive Officer. The Commercial organization manages our commercial marketing, optimizes our commodity flows and positions, and monitors risks related to our upstream and downstream businesses.

Commodity Price Risk

We operate in the worldwide crude oil, bitumen, refined products, natural gas, natural gas liquids, LNG 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.

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 demands.
- 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 floating market prices.
- 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 capture market opportunities such as moving physical commodities to more profitable locations, storing commodities to capture seasonal or time premiums, and blending commodities to capture quality upgrades. We may use derivatives to optimize these activities.

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 we hold or issue, including commodity purchases and sales contracts recorded on the balance sheet at December 31, 2011, as derivative instruments. 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, 2011 and 2010, was immaterial to our consolidated cash flows and net income attributable to ConocoPhillips. The VaR for instruments held for purposes other than trading at December 31, 2011 and 2010, was also immaterial to our cash flows and net income attributable to ConocoPhillips.

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Interest Rate Risk

The following table provides information about our financial instruments that are sensitive to changes in U.S. interest rates. The debt portion of the table presents principal cash flows and related weighted-average interest rates by expected maturity dates. Weighted-average variable rates are based on effective rates 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. The joint venture acquisition obligation portion of the table presents principal cash flows of the fixed-rate 5.3 percent joint venture acquisition obligation owed to FCCL Partnership. The fair value of the obligation is estimated based on the net present value of the future cash flows, discounted at year-end 2011 and 2010 effective yield rates of 1.24 percent and 1.87 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					
	Debt				Joint Venture Acquisition Obligation	
Expected Maturity Date	Fixed Rate Maturity	Average Interest Rate	Floating Rate Maturity	Average Interest Rate	Fixed Rate Maturity	Average Interest Rate
Year-End 2011						
2012	**$ 918**	**4.80%**	**$ 3**	**0.38%**	**$ 732**	**5.30%**
2013	**1,262**	**5.33**	**-**	**-**	**772**	**5.30**
2014	**1,511**	**4.77**	**-**	**-**	**814**	**5.30**
2015	**1,513**	**4.62**	**15**	**2.01**	**858**	**5.30**
2016	**1,287**	**5.54**	**1,128**	**0.51**	**904**	**5.30**
Remaining years	**14,008**	**6.52**	**498**	**0.38**	**234**	**5.30**
Total	**$ 20,499**		**$ 1,644**		**$ 4,314**	
Fair value	**$ 25,421**		**$ 1,644**		**$ 4,820**	
Year-End 2010						
2011	$ 853	7.62%	$ -	-%	$ 695	5.30%
2012	916	4.80	1,185	0.51	732	5.30
2013	1,262	5.33	-	-	772	5.30
2014	1,513	4.77	-	-	814	5.30
2015	1,514	4.62	64	2.05	858	5.30
Remaining years	15,291	6.44	498	0.38	1,138	5.30
Total	$ 21,349		$ 1,747		$ 5,009	
Fair value	$ 24,397		$ 1,747		$ 5,600	

During the second quarter of 2010, we executed interest rate swaps to synthetically convert $500 million of our 4.60% fixed-rate notes due in 2015 to a floating rate based on the London Interbank Offered Rate (LIBOR). These swaps qualify for and are designated as fair-value hedges using the short-cut method of hedge accounting. The short-cut method permits the assumption that changes in the value of the derivative perfectly offset changes in the value of the debt; therefore, no gain or loss has been recognized due to hedge ineffectiveness. These adjustments to the fair values of the interest rate swaps and hedged debt have not been material.

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Foreign Currency Exchange 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 certain foreign currency exchange rate exposures, such as firm commitments for capital projects or local currency tax payments, dividends and cash returns from net investments in foreign affiliates to be remitted within the coming year.

At December 31, 2011 and 2010, we held foreign currency exchange forwards hedging cross-border commercial activity and foreign currency exchange swaps hedging short-term intercompany loans between European subsidiaries and a U.S. subsidiary. Although these forwards and swaps hedge exposures to fluctuations in exchange rates, we elected not to utilize hedge accounting. As a result, the change in the fair value of these foreign currency exchange derivatives 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, and since our aggregate position in the forwards was not material, there would be no material impact to our income from an adverse hypothetical 10 percent change in the December 31, 2011, or 2010, exchange rates. The notional and fair market values of these positions at December 31, 2011 and 2010, were as follows:

		USD00000	**USD00000**	**USD00000**	**USD00000**
			In Millions		
Foreign Currency Exchange Derivatives		Notional*		Fair Market Value**	
		2011	2010	**2011**	2010
Sell U.S. dollar, buy euro	USD	**219**	-	**$ (8)**	-
Sell U.S. dollar, buy British pound	USD	**790**	4	**-**	(3)
Sell U.S. dollar, buy Canadian dollar	USD	**648**	562	**-**	8
Sell U.S. dollar, buy Norwegian krone	USD	**292**	3	**(7)**	-
Buy euro, sell the Norwegian krone	EUR	**3**	-	**-**	-
Sell euro, buy British pound	EUR	**64**	253	**5**	1

**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.

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Item 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

CONOCOPHILLIPS

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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 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, 2011. 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, 2011.

Ernst & Young LLP has issued an audit report on the company s internal control over financial reporting as of December 31, 2011, and their report is included herein.

/s/ James J. Mulva

James J. Mulva
Chairman, President and
Chief Executive Officer
February 21, 2012

/s/ Jeff W. Sheets

Jeff W. Sheets
Senior Vice President, Finance
and Chief Financial Officer

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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, 2011 and 2010, and the related consolidated statements of income, comprehensive income, changes in equity, and cash flows for each of the three years in the period ended December 31, 2011. 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, 2011 and 2010, and the consolidated results of its operations and its cash flows for each of the three years in the period ended December 31, 2011, 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.

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, 2011, 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 21, 2012 expressed an unqualified opinion thereon.

/s/ Ernst & Young LLP

Houston, Texas

February 21, 2012

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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, 2011, 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, 2011, based on the COSO criteria.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the 2011 consolidated financial statements of ConocoPhillips and our report dated February 21, 2012 expressed an unqualified opinion thereon.

/s/ Ernst & Young LLP

Houston, Texas

February 21, 2012

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Consolidated Income Statement **ConocoPhillips**

Years Ended December 31	Millions of Dollars		
	2011	2010	2009
Revenues and Other Income			
Sales and other operating revenues*	**$ 244,813**	189,441	149,341
Equity in earnings of affiliates	**4,077**	3,133	2,531
Gain on dispositions	**2,007**	5,803	160
Other income	**329**	278	358
Total Revenues and Other Income	**251,226**	198,655	152,390
Costs and Expenses			
Purchased crude oil, natural gas and products	**185,867**	135,751	102,433
Production and operating expenses	**10,770**	10,635	10,339
Selling, general and administrative expenses	**2,078**	2,005	1,830
Exploration expenses	**1,066**	1,155	1,182
Depreciation, depletion and amortization	**7,934**	9,060	9,295
Impairments	**792**	1,780	535
Taxes other than income taxes*	**18,307**	16,793	15,529
Accretion on discounted liabilities	**455**	447	422
Interest and debt expense	**972**	1,187	1,289
Foreign currency transaction (gains) losses	**(16)**	92	(46)
Total Costs and Expenses	**228,225**	178,905	142,808
Income before income taxes	**23,001**	19,750	9,582
Provision for income taxes	**10,499**	8,333	5,090
Net income	**12,502**	11,417	4,492
Less: net income attributable to noncontrolling interests	**(66)**	(59)	(78)
Net Income Attributable to ConocoPhillips	**$ 12,436**	11,358	4,414
Net Income Attributable to ConocoPhillips Per Share of Common Stock *(dollars)*			
Basic	**$ 9.04**	7.68	2.96
Diluted	**8.97**	7.62	2.94
Average Common Shares Outstanding *(in thousands)*			
Basic	**1,375,035**	1,479,330	1,487,650
Diluted	**1,387,100**	1,491,067	1,497,608
**Includes excise taxes on petroleum products sales:*	***$ 13,954***	*13,689*	*13,325*

See Notes to Consolidated Financial Statements.

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Consolidated Statement of Comprehensive Income **ConocoPhillips**

Years Ended December 31	Millions of Dollars		
	2011	2010	2009
Net Income	**$ 12,502**	11,417	4,492
Other comprehensive income (loss)			
Defined benefit plans			
Prior service cost (credit) arising during the period	**19**	(13)	-
Reclassification adjustment for amortization of prior service cost included in net income	**2**	15	21
Net change	**21**	2	21
Net actuarial loss arising during the period	**(1,185)**	(9)	(388)
Reclassification adjustment for amortization of prior net losses included in net income	**226**	215	206
Net change	**(959)**	206	(182)
Nonsponsored plans*	**(50)**	5	39
Income taxes on defined benefit plans	**375**	(67)	52
Defined benefit plans, net of tax	**(613)**	146	(70)
Unrealized holding gain on securities**	**8**	631	-
Reclassification adjustment for gain included in net income	**(255)**	(384)	-
Income taxes on unrealized holding gain on securities	**89**	(89)	-
Unrealized gain on securities, net of tax	**(158)**	158	-
Foreign currency translation adjustments	**(387)**	1,417	5,092
Reclassification adjustment for gain included in net income	**(516)**	-	-
Income taxes on foreign currency translation adjustments	**(14)**	(13)	(85)
Foreign currency translation adjustments, net of tax	**(917)**	1,404	5,007
Hedging activities	**1**	-	(2)
Income taxes on hedging activities	**-**	-	5
Hedging activities, net of tax	**1**	-	3
Other comprehensive income (loss), net of tax	**(1,687)**	1,708	4,940
Comprehensive income	**10,815**	13,125	9,432
Less: comprehensive income attributable to noncontrolling interests	**(66)**	(59)	(78)
Comprehensive Income Attributable to ConocoPhillips	**$ 10,749**	13,066	9,354

**Plans for which ConocoPhillips is not the primary obligor primarily those administered by equity affiliates.*

***Available-for-sale securities of LUKOIL.*

See Notes to Consolidated Financial Statements.

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Consolidated Balance Sheet **ConocoPhillips**

At December 31	Millions of Dollars 2011	2010
Assets		
Cash and cash equivalents	**$ 5,780**	9,454
Short-term investments*	**581**	973
Accounts and notes receivable (net of allowance of $30 million in 2011 and $32 million in 2010)	**14,648**	13,787
Accounts and notes receivable related parties	**1,878**	2,025
Investment in LUKOIL	**-**	1,083
Inventories	**4,631**	5,197
Prepaid expenses and other current assets	**2,700**	2,141
Total Current Assets	**30,218**	34,660
Investments and long-term receivables	**32,108**	31,581
Loans and advances related parties	**1,675**	2,180
Net properties, plants and equipment	**84,180**	82,554
Goodwill	**3,332**	3,633
Intangibles	**745**	801
Other assets	**972**	905
Total Assets	**$ 153,230**	156,314
Liabilities		
Accounts payable	**$ 17,973**	16,613
Accounts payable related parties	**1,680**	1,786
Short-term debt	**1,013**	936
Accrued income and other taxes	**4,220**	4,874
Employee benefit obligations	**1,111**	1,081
Other accruals	**2,071**	2,129
Total Current Liabilities	**28,068**	27,419
Long-term debt	**21,610**	22,656
Asset retirement obligations and accrued environmental costs	**9,329**	9,199
Joint venture acquisition obligation related party	**3,582**	4,314
Deferred income taxes	**18,055**	17,335
Employee benefit obligations	**4,068**	3,683
Other liabilities and deferred credits	**2,784**	2,599
Total Liabilities	**87,496**	87,205
Equity		
Common stock (2,500,000,000 shares authorized at $.01 par value)		
Issued (2011 1,749,550,587 shares; 2010 1,740,529,279 shares)		
Par value	**17**	17
Capital in excess of par	**44,725**	44,132
Grantor trusts (at cost: 2010 36,890,375 shares)	**-**	(633)
Treasury stock (at cost: 2011 463,880,628 shares; 2010 272,873,537 shares)	**(31,787)**	(20,077)

Accumulated other comprehensive income	**3,086**	4,773
Unearned employee compensation	**(11)**	(47)
Retained earnings	**49,194**	40,397
Total Common Stockholders Equity	**65,224**	68,562
Noncontrolling interests	**510**	547
Total Equity	**65,734**	69,109
Total Liabilities and Equity	**$ 153,230**	156,314
**Includes marketable securities of:*	*$ 232*	*602*

See Notes to Consolidated Financial Statements.

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Consolidated Statement of Cash Flows **ConocoPhillips**

Years Ended December 31		Millions of Dollars		
		2011	2010	2009
Cash Flows From Operating Activities				
Net income	$	**12,502**	11,417	4,492
Adjustments to reconcile net income to net cash provided by operating activities				
Depreciation, depletion and amortization		**7,934**	9,060	9,295
Impairments		**792**	1,780	535
Dry hole costs and leasehold impairments		**470**	477	606
Accretion on discounted liabilities		**455**	447	422
Deferred taxes		**1,287**	(878)	(1,115)
Undistributed equity earnings		**(1,077)**	(1,073)	(1,254)
Gain on dispositions		**(2,007)**	(5,803)	(160)
Other		**(359)**	(249)	196
Working capital adjustments				
Decrease (increase) in accounts and notes receivable		**(1,169)**	(2,427)	(1,106)
Decrease (increase) in inventories		**556**	(363)	320
Decrease (increase) in prepaid expenses and other current assets		**(306)**	43	282
Increase (decrease) in accounts payable		**1,290**	2,887	1,612
Increase (decrease) in taxes and other accruals		**(722)**	1,727	(1,646)
Net Cash Provided by Operating Activities		**19,646**	17,045	12,479
Cash Flows From Investing Activities				
Capital expenditures and investments		**(13,266)**	(9,761)	(10,861)
Proceeds from asset dispositions		**4,820**	15,372	1,270
Net sales (purchases) of short-term investments		**400**	(982)	-
Long-term advances/loans related parties		**(9)**	(313)	(525)
Collection of advances/loans related parties		**648**	115	93
Other		**392**	234	88
Net Cash Provided by (Used in) Investing Activities		**(7,015)**	4,665	(9,935)
Cash Flows From Financing Activities				
Issuance of debt		**-**	118	9,087
Repayment of debt		**(961)**	(5,320)	(7,858)
Issuance of company common stock		**96**	133	13
Repurchase of company common stock		**(11,123)**	(3,866)	-
Dividends paid on company common stock		**(3,632)**	(3,175)	(2,832)
Other		**(685)**	(709)	(1,265)
Net Cash Used in Financing Activities		**(16,305)**	(12,819)	(2,855)
Effect of Exchange Rate Changes on Cash and Cash Equivalents		**-**	21	98
Net Change in Cash and Cash Equivalents		**(3,674)**	8,912	(213)
Cash and cash equivalents at beginning of year		**9,454**	542	755

Cash and Cash Equivalents at End of Year	$	**5,780**	9,454	542

See Notes to Consolidated Financial Statements.

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Consolidated Statement of Changes in Equity **ConocoPhillips**

	Millions of Dollars									
	Attributable to ConocoPhillips									
	Common Stock									
		Par Value	Capital in Excess of Par	Treasury Stock	Grantor Trusts	Accum. Other Comprehensive Income (Loss)	Unearned Employee Compensation	Retained Earnings	Noncontrolling Interests	Total
December 31, 2008	$	17	43,396	(16,211)	(702)	(1,875)	(102)	30,642	1,100	56,265
Net income								4,414	78	4,492
Other comprehensive income						4,940				4,940
Cash dividends paid on company common stock								(2,832)		(2,832)
Distributions to noncontrolling interests and other									(588)	(588)
Distributed under benefit plans			285		35					320
Recognition of unearned compensation							26			26
Other								(10)		(10)
December 31, 2009		17	43,681	(16,211)	(667)	3,065	(76)	32,214	590	62,613
Net income								11,358	59	11,417
Other comprehensive income						1,708				1,708
Cash dividends paid on company common stock								(3,175)		(3,175)
Repurchase of company common stock				(3,866)						(3,866)
Distributions to noncontrolling interests and other									(102)	(102)
Distributed under benefit plans			451		34					485
Recognition of unearned compensation							29			29
December 31, 2010		17	44,132	(20,077)	(633)	4,773	(47)	40,397	547	69,109
Net income								**12,436**	**66**	**12,502**
Other comprehensive income (loss)						**(1,687)**				**(1,687)**
Cash dividends paid on company common stock								**(3,632)**		**(3,632)**
Repurchase of company common stock				**(11,133)**	**10**					**(11,123)**
Distributions to noncontrolling interests and other									**(103)**	**(103)**
Distributed under benefit plans			**593**	**33**	**13**					**639**
Recognition of unearned compensation							**36**			**36**
Transfer to treasury stock				**(610)**	**610**					**-**
Other								**(7)**		**(7)**
December 31, 2011	**$**	**17**	**44,725**	**(31,787)**	**-**	**3,086**	**(11)**	**49,194**	**510**	**65,734**

See Notes to Consolidated Financial Statements.

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Notes to Consolidated Financial Statements

Note 1 Accounting Policies

- **Consolidation Principles and Investments** Our consolidated financial statements include the accounts of majority-owned, controlled subsidiaries and variable interest entities where we are the primary beneficiary. The equity method is used to account for investments in affiliates in which we have the ability to exert significant influence over the affiliates operating and financial policies. When we do not have the ability to exert significant influence, the investment is either classified as available-for-sale if fair value is readily determinable, or the cost method is used if fair value is not readily determinable. Undivided interests in oil and gas joint ventures, pipelines, natural gas plants and terminals are consolidated on a proportionate basis. Other securities and investments are generally carried at cost.

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

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

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

Revenues associated with producing 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 transactions commonly called buy/sell contracts, in which the purchase and sale of inventory with the same counterparty are entered into in contemplation of one another, are combined and reported net (i.e., on the same income statement line).

- **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 90 days or less from their date of purchase. They are carried at cost plus accrued interest, which approximates fair value.

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- **Short-Term Investments** Investments in bank time deposits and marketable securities (commercial paper and government obligations) with original maturities of greater than 90 days but less than one year are classified as short-term investments. See Note 16 Financial Instruments and Derivative Contracts, for additional information on these held-to-maturity financial instruments.

- **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 and petroleum products 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 using various methods, including the weighted-average-cost method, and the first-in, first-out (FIFO) method, consistent with industry practice.

- **Fair Value Measurements** We 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.

- **Derivative Instruments** Derivative instruments are recorded on the balance sheet at fair value. If the right of offset exists and certain other criteria are met, derivative assets and liabilities with the same counterparty are netted on the balance sheet and the 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 not accounted for as hedges 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 are recognized in other comprehensive income and appear on the balance sheet in accumulated other comprehensive income until the hedged transaction is recognized in earnings; however, to the extent the change in the value of the derivative exceeds the change in the anticipated cash flows of the hedged transaction, the excess gains or losses will be recognized immediately in earnings.

- **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 (PP&E). Leasehold impairment is recognized based on exploratory experience and management s judgment. Upon achievement of all conditions necessary for reserves to be classified 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

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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 resources 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 dry holes when it judges the potential field does not warrant further investment in the near term. See Note 8 Suspended Wells, 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.

n **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.

n **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. These indefinite lived intangibles 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 believed to be consistent with those used by principal market participants, or upon estimated replacement cost, if expected future cash flows from the intangible asset are not determinable.

n **Goodwill** Goodwill resulting from a business combination 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.

n **Depreciation and Amortization** Depreciation and amortization of PP&E on producing hydrocarbon properties and certain pipeline assets (those which are expected to have a declining utilization pattern), are determined by the unit-of-production method. Depreciation and amortization of all other PP&E 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).

n **Impairment of Properties, Plants and Equipment** PP&E 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 and annually in the fourth quarter following updates to corporate planning assumptions. 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, or at an entire complex level for downstream assets. Because there usually is a lack of quoted market prices for long-lived assets, the fair value of impaired assets is typically determined based on the present values of expected future cash flows using discount rates believed to be consistent with those used by principal market participants 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, with fair value determined using a binding negotiated price, if available, or present value of expected future cash flows as previously described.

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. For E&P assets, 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.

n **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 and annually following updates to corporate planning assumptions. When such a condition is judgmentally determined to be other than temporary, the carrying value of the investment is written down to fair 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 believed to be consistent with those used by principal market participants, plus market analysis of comparable assets owned by the investee, if appropriate.

n **Maintenance and Repairs** Costs of maintenance and repairs, which are not significant improvements, are expensed when incurred. Major refinery turnarounds are expensed as incurred.

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

n **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 the Gain on dispositions line of our consolidated income statement. When less than complete units of depreciable property are disposed of or retired, the difference between asset cost and salvage value is charged or credited to accumulated depreciation.

n **Asset Retirement Obligations and Environmental Costs** The fair value of legal obligations to retire and remove long-lived assets are recorded 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 PP&E. Over time the liability is increased for the change in its present value, and the capitalized cost in PP&E is depreciated over the useful life of the related asset. For additional information, see Note 11 Asset Retirement Obligations and Accrued Environmental Costs, for additional information.

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Environmental expenditures are expensed or capitalized, depending upon their future economic benefit. Expenditures relating to an existing condition caused by past operations, and those having no 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.

n **Guarantees** 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 indicating the liability is essentially relieved or amortize it over an appropriate time period as the fair value of our guarantee exposure declines over time. We amortize the guarantee liability to the related income statement line item based on the nature of the guarantee. When it becomes probable that we will have to perform on a guarantee, we accrue a separate liability if it is reasonably estimable, based on the facts and circumstances at that time. We reverse the fair value liability only when there is no further exposure under the guarantee.

n **Stock-Based Compensation** We recognize stock-based compensation expense over the shorter of the service period (i.e., the stated period of time required to earn the award) or the period beginning at the start of the service period and ending when an employee first becomes eligible for retirement. 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.

n **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.

n **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.

n **Net Income Per Share of Common Stock** Basic net income per share of common stock is calculated based upon the daily weighted-average number of common shares outstanding during the year, including unallocated shares held by the stock savings feature of the ConocoPhillips Savings Plan. Also, this calculation includes fully vested stock and unit awards that have not been issued. Diluted 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. For the purpose of the 2009 earnings per share calculation, net income attributable to ConocoPhillips was reduced by $12 million for the excess of the amount paid for the redemption of a noncontrolling interest over its carrying value, which was charged directly to retained earnings. Treasury stock and shares held by grantor trusts are excluded from the daily weighted-average number of common shares outstanding in both calculations.

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Note 2 Changes in Accounting Principles

Comprehensive Income

Effective December 31, 2011, we early adopted Financial Accounting Standards Board (FASB) Accounting Standards Update (ASU) No. 2011-05, Presentation of Comprehensive Income. This ASU amends FASB Accounting Standards Codification (ASC) Topic 220, Comprehensive Income, by requiring a more prominent presentation of the components of other comprehensive income. We elected the two-statement approach presenting other comprehensive income in a separate statement immediately following the income statement. On December 23, 2011, the FASB issued ASU 2011-12, Deferral of the Effective Date for Amendments to the Presentation of Reclassifications of Items Out of Accumulated Other Comprehensive Income in ASU No. 2011-05. ASU 2011-12 defers the ASU 2011-05 requirement to present items reclassified into net income from other comprehensive income. This deferral only impacted the presentation requirement on the consolidated income statement.

Note 3 Variable Interest Entities (VIEs)

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

We have an agreement with Freeport LNG Development, L.P. (Freeport LNG) to participate in an LNG receiving terminal in Quintana, Texas. We have no ownership in Freeport LNG; however, we own a 50 percent interest in Freeport LNG GP, Inc. (Freeport GP), which serves as the general partner 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. Freeport LNG began making loan repayments in September 2008, and the loan balance outstanding as of December 31, 2011, was $612 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.

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Note 4 Inventories

Inventories at December 31 were:

	Millions of Dollars	
	2011	2010
Crude oil and petroleum products	**$ 3,633**	4,254
Materials, supplies and other	**998**	943
	$ 4,631	5,197

Inventories valued on the LIFO basis totaled $3,387 million and $4,051 million at December 31, 2011 and 2010, respectively. The estimated excess of current replacement cost over LIFO cost of inventories amounted to approximately $8,400 million and $6,800 million at December 31, 2011 and 2010, respectively. In 2011, a liquidation of LIFO inventory values increased net income attributable to ConocoPhillips $160 million, of which $155 million was attributable to the R&M segment.

Note 5 Assets Held for Sale or Sold

In December 2011, we sold our ownership interests in Colonial Pipeline Company and Seaway Crude Pipeline Company. The total carrying value of these assets, which were included in our R&M segment, was $348 million, which included $104 million of investment in equity affiliates and $244 million of allocated goodwill. The $1,661 million before-tax gain on these dispositions was included in the Gain on dispositions line in the consolidated income statement.

In June 2010, we sold our 9.03 percent interest in the Syncrude Canada Ltd. joint venture for $4.6 billion. The $2.9 billion before-tax gain was included in the Gain on dispositions line of our consolidated income statement. At the time of disposition, Syncrude had a net carrying value of $1.75 billion, which included $1.97 billion of PP&E, and was included in the E&P segment.

In February 2012, we signed definitive agreements to sell our Vietnam E&P business for $1.29 billion, excluding customary working capital adjustments. The transaction is expected to close in the first half of 2012. At December 31, 2011, this business had a net carrying value of approximately $150 million, which included PP&E of $350 million.

See Note 6 Investments, Loans and Long-Term Receivables, for information on the disposition of our investment in OAO LUKOIL during 2010 and 2011.

Note 6 Investments, Loans and Long-Term Receivables

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

	Millions of Dollars	
	2011	2010
Equity investments	**$ 30,985**	30,055
Loans and advances related parties	**1,675**	2,180
Long-term receivables	**559**	922
Other investments	**564**	604

	$ 33,783	33,761

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Equity Investments

Affiliated companies in which we had a significant equity investment at December 31, 2011, included:

- Australia Pacific LNG (APLNG) 42.5 percent owned joint venture with Origin Energy (42.5 percent) and China Petrochemical Corporation (Sinopec) (15 percent) to develop coalbed methane production from the Bowen and Surat basins in Queensland, Australia, as well as process and export LNG.
- FCCL Partnership 50 percent owned business venture with Cenovus Energy Inc. produces bitumen in the Athabasca oil sands in northeastern Alberta and sells the bitumen blend.
- WRB Refining LP 50 percent owned business venture with Cenovus owns the Wood River and Borger refineries, which process crude oil into refined products.
- Qatar Liquefied Gas Company Limited 3 (QG3) 30 percent owned joint venture with affiliates of Qatar Petroleum (68.5 percent) and Mitsui & Co., Ltd. (1.5 percent) produces and liquefies natural gas from Qatar s North Field.
- 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.

Summarized 100 percent financial information for equity method investments in affiliated companies, combined, was as follows (information includes LUKOIL until loss of significant influence):

		Millions of Dollars		
		2011	2010	2009
Revenues	$	**77,263**	105,589	128,881
Income before income taxes		**11,958**	11,250	12,121
Net income		**11,089**	9,495	9,145
Current assets		**21,530**	14,039	36,139
Noncurrent assets		**76,300**	79,411	126,163
Current liabilities		**9,708**	9,325	22,483
Noncurrent liabilities		**22,993**	24,412	30,960

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, 2011, retained earnings included $2,814 million related to the undistributed earnings of affiliated companies. Dividends received from affiliates were $3,670 million, $2,282 million and $1,727 million in 2011, 2010 and 2009, respectively.

APLNG

In 2008, we closed on a transaction with Origin Energy, an integrated Australian energy company, to further enhance our long-term Australasian natural gas business. APLNG is focused 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. Origin is the operator of APLNG s production and pipeline system, while we will operate the LNG facility.

In April 2011, APLNG and Sinopec signed definitive agreements for APLNG to supply up to 4.3 million tonnes of LNG per year for 20 years. The agreements also specified terms under which Sinopec subscribed for a 15 percent equity interest in APLNG, with both our ownership interest and Origin Energy s ownership interest diluting to 42.5 percent. The Subscription Agreement was completed in August 2011, and we recorded a loss on disposition of $279 million before- and after-tax from the dilution. The book value of our investment in APLNG was reduced by $795 million, and we reduced the currency translation adjustment associated with our investment by $516 million.

In November 2011, APLNG signed a binding Heads of Agreement with Japan-based Kansai Electric for the sale of approximately 1 million tonnes of LNG per year for 20 years. Under the terms of the agreement, Kansai Electric will be supplied LNG beginning in mid-2016. The agreement is also subject to a final investment decision on the second LNG train, which is expected in the first half of 2012.

In January 2012, APLNG and Sinopec signed an amendment to their existing LNG sales agreement for the sale and purchase of an additional 3.3 million tonnes of LNG per year through 2035, subject to a final investment decision on the second LNG train. This agreement, in combination with the Kansai Electric agreement, finalizes the marketing of the second train. In conjunction with the LNG sale, the parties have also agreed for Sinopec to subscribe for additional shares in APLNG, which will raise its equity interest from 15 percent to 25 percent. As a result, both our ownership interest and Origin Energy s ownership interest would dilute from 42.5 percent to 37.5 percent. We expect to record a loss of approximately $135 million after-tax from the dilution.

At December 31, 2011, the book value of our equity method investment in APLNG was $9,467 million, which includes $2,716 million of cumulative translation effects due to a strengthening Australian dollar relative to the U.S. dollar. Our 42.5 percent share of the historical cost basis net assets of APLNG on its books under U.S. generally accepted accounting principles was $2,380 million, resulting in a basis difference of $7,087 million on our books. The amortizable portion of the basis difference, $5,192 million associated with PP&E, has been allocated on a relative fair value basis to 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, which, if required, would result in acceleration of basis difference amortization. As the joint venture begins producing natural gas from each license, we amortize the basis difference allocated to that license using the unit-of-production method. Included in net income attributable to ConocoPhillips for 2011, 2010 and 2009 was after-tax expense of $17 million, $5 million and $4 million, respectively, representing the amortization of this basis difference on currently producing licenses.

FCCL and WRB

We have two 50/50 North American heavy oil business ventures with Cenovus Energy Inc.: FCCL Partnership, a Canadian upstream general partnership, and WRB Refining LP, a U.S. downstream limited partnership. We use the equity method of accounting for both entities, with the operating results of our investment in FCCL reflecting the use of the successful efforts method of accounting for oil and gas exploration and development activities.

At December 31, 2011, the book value of our investment in FCCL was $9,044 million. 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. Cenovus 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 that began in 2007. For additional information on this obligation, see Note 13 Joint Venture Acquisition Obligation.

At December 31, 2011, the book value of our investment in WRB was $3,722 million. 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 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 26 years, which was the estimated remaining useful life of the refineries PP&E at the closing date. The basis difference at December 31, 2011, was $3,918 million. Equity earnings in 2011, 2010 and 2009 were increased by $185 million, $243 million and $209 million, respectively, due to amortization of the basis difference. We are the operator and managing partner of WRB. Cenovus is obligated to contribute $7.5 billion, plus accrued interest, to WRB over a 10-year period that began in 2007.

QG3

QG3 is a joint venture that owns an integrated large-scale LNG project located in Qatar. We provided project financing, with a current outstanding balance of $1,159 million as described below under Loans and Long-term Receivables. At December 31, 2011, the book value of our equity method investment in QG3 was

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$931 million. We have terminal and pipeline use agreements with Golden Pass LNG Terminal and affiliated Golden Pass Pipeline near Port Arthur, Texas, in which we have a 12.4 percent interest, intended to provide us with terminal and pipeline capacity for the receipt, storage and regasification of LNG purchased from QG3. However, currently the LNG from QG3 is being sold to markets outside of the United States.

DCP Midstream

DCP Midstream owns and operates gas plants, gathering systems, storage facilities and fractionation plants. At December 31, 2011, the book value of our equity method investment in DCP Midstream was $927 million. DCP Midstream markets a portion of its natural gas liquids to us and CPChem under a supply agreement that continues at the current volume commitment with a primary term ending 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, 2011, the book value of our equity method investment in CPChem was $2,998 million. 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.

In anticipation of the separation of our downstream businesses (including CPChem), we reached agreement with Chevron Corporation regarding CPChem that provides for CPChem to: (i) prior to the separation, suspend all cash distributions to its owners and accumulate its excess cash; and (ii) after the separation, use the accumulated cash and its excess cash flow to pay down $1 billion of its outstanding fixed-rate bonds on an accelerated basis. During this period of bond repayment, CPChem is not required to make any cash distributions to its owners.

LUKOIL

LUKOIL is an integrated energy company headquartered in Russia. We completed the disposition of our interest in LUKOIL during the first quarter of 2011, realizing a before-tax gain of $360 million, which was included in the Gain on dispositions line of our consolidated income statement, and cash proceeds of $1,243 million. Our ownership interest was 2.25 percent at December 31, 2010, and 20 percent at December 31, 2009.

On July 28, 2010, we announced our intention to sell our entire interest in LUKOIL, then consisting of 163.4 million shares. This decision was implemented as follows:

- On July 28, 2010, we entered into a stock purchase and option agreement (the Agreement) with a wholly owned subsidiary of LUKOIL, pursuant to which such subsidiary purchased 64.6 million shares from us at a price of $53.25 per share, or $3,442 million in total. This transaction closed on August 16, 2010.
- Also pursuant to the Agreement, the LUKOIL subsidiary had a 60-day option, expiring on September 26, 2010, to purchase any or all of our interest remaining at the time of exercise of the option, at a price of $56 per share. Upon exercise of this option, we sold 42.5 million shares on September 29, 2010, for proceeds of $2,380 million.
- Finally, we sold our remaining shares in the open market subject to the terms of the Shareholder Agreement, with the final disposition of all shares occurring in the first quarter of 2011. The cost basis for shares sold was average cost.

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During the third quarter of 2010, our ownership interest declined to a level at which we were no longer able to exercise significant influence over the operating and financial policies of LUKOIL. Accordingly, at the end of the third quarter of 2010, we stopped applying the equity method of accounting for our remaining investment in LUKOIL, and we reclassified the investment from Investments and long-term receivables to current assets on our consolidated balance sheet as an available-for-sale equity security.

In total, during 2010, we sold 151 million shares of LUKOIL for $8,345 million, realizing a before-tax gain on disposition of $1,749 million, which was included in the Gain on dispositions line of our consolidated income statement. Included in these amounts were sales proceeds of $1,793 million and a realized before-tax gain of $437 million incurred subsequent to classifying the investment as available-for-sale. The cost basis for shares sold is average cost.

At December 31, 2010, our then remaining investment in LUKOIL was carried at fair value of $1,083 million, reflecting a closing price of LUKOIL American Depositary Receipts (ADRs) on the London Stock Exchange of $56.50 per share. The carrying value reflected a pre-tax unrealized gain over our cost basis of $247 million. This unrealized gain, net of related income taxes, was reported as a component of accumulated other comprehensive income. The fair value was categorized as Level 1 in the fair value hierarchy.

While applying the equity method of accounting, a negative basis difference existed which was primarily amortized on a straight-line basis over a 22-year useful life as an increase to equity earnings. Equity earnings in 2010 and 2009 were increased $155 million and $157 million, respectively, due to amortization of this basis difference.

Loans and Long-term Receivables

As part of our normal ongoing business operations and consistent with industry practice, we enter into numerous agreements with other parties to pursue business opportunities. Included in such activity are loans and long-term receivables to certain affiliated and non-affiliated companies. Loans are recorded when cash is transferred or seller financing is provided to the affiliated or non-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 and long-term receivables are assessed for impairment when events indicate the loan balance may not be fully recovered.

At December 31, 2011, significant loans to affiliated companies include the following:

- $612 million in loan financing to Freeport LNG Development, L.P. for the construction of an LNG receiving terminal that became operational in June 2008. Freeport began making repayments in 2008 and is required to continue making repayments through full repayment of the loan in 2026. Repayment by Freeport is supported by process-or-pay capacity service payments made by us to Freeport under our terminal use agreement.

- $1,159 million in project financing to QG3. We own a 30 percent interest in QG3, for which we use the equity method of accounting. The other participants in the project are affiliates of Qatar Petroleum and Mitsui. QG3 secured project financing of $4.0 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. On December 15, 2011, QG3 achieved financial completion and all project loan facilities became nonrecourse to the project participants. Bi-annual repayments began in January 2011 and will extend through July 2022.

The long-term portion of these loans are included in the Loans and advances related parties line on the consolidated balance sheet, while the short-term portion is in Accounts and notes receivable related parties.

WRB Refining LP fully repaid its outstanding loans from us with payments of $550 million in 2011.

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In November 2011, a long-term loan to a non-affiliated company related to seller financing of U.S. retail marketing assets was refinanced, which resulted in a receipt of $365 million. As part of the refinancing, we provided loan guarantees in support of $191 million of the total refinancing.

Long-term receivables and the long-term portion of these loans are included in the Investments and long-term receivables line on the consolidated balance sheet, while the short-term portion related to non-affiliate loans is in Accounts and notes receivable.

Other

We have investments remeasured at fair value on a recurring basis to support certain nonqualified deferred compensation plans. The fair value of these assets at December 31, 2011, was $336 million, and at December 31, 2010, was $325 million. Substantially the entire value is categorized in Level 1 of the fair value hierarchy. These investments are measured at fair value using a market approach based on quotations from national securities exchanges.

Merey Sweeny, L.P. (MSLP) owns a delayed coker and related facilities at the Sweeny Refinery. MSLP processes our long residue, which is produced from heavy sour crude oil, for a processing fee. Fuel-grade petroleum coke is produced as a by-product and becomes the property of MSLP. Prior to August 28, 2009, MSLP was owned 50/50 by us and Petróleos de Venezuela S.A. (PDVSA). Under the agreements that govern the relationships between the partners, certain defaults by PDVSA with respect to supply of crude oil to the Sweeny Refinery gave us the right to acquire PDVSA s 50 percent ownership interest in MSLP, which we exercised on August 28, 2009. PDVSA has initiated arbitration with the International Chamber of Commerce challenging the exercise of the call right and claiming it was invalid. The arbitral tribunal is scheduled to hold hearings on the merits of the dispute in December 2012. We continue to use the equity method of accounting for our investment in MSLP.

Note 7 Properties, Plants and Equipment

PP&E is 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					
	2011			2010		
	Gross PP&E	Accum. DD&A	Net PP&E	Gross PP&E	Accum. DD&A	Net PP&E
E&P	$ **124,111**	**55,565**	**68,546**	116,805	50,501	66,304
Midstream	**135**	**86**	**49**	128	80	48
R&M	**22,096**	**8,128**	**13,968**	23,579	8,999	14,580
LUKOIL Investment	**-**	**-**	**-**	-	-	-
Chemicals	**-**	**-**	**-**	-	-	-
Emerging Businesses	**1,023**	**220**	**803**	981	161	820
Corporate and Other	**1,844**	**1,030**	**814**	1,732	930	802
	$ **149,209**	**65,029**	**84,180**	143,225	60,671	82,554

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Note 8 Suspended Wells

The following table reflects the net changes in suspended exploratory well costs during 2011, 2010 and 2009:

	Millions of Dollars		
	2011	2010	2009
Beginning balance at January 1	$ **1,013**	908	660
Additions pending the determination of proved reserves	**96**	216	342
Reclassifications to proved properties	**(72)**	(106)	(39)
Sales of suspended well investment	**-**	(4)	(21)
Charged to dry hole expense	**-**	(1)	(34)
Ending balance at December 31	$ **1,037**	1,013	908

The following table provides an aging of suspended well balances at December 31, 2011, 2010 and 2009:

	Millions of Dollars		
	2011	2010	2009
Exploratory well costs capitalized for a period of one year or less	$ **115**	220	319
Exploratory well costs capitalized for a period greater than one year	**922**	793	589
Ending balance	$ **1,037**	1,013	908
Number of projects that have exploratory well costs that have been capitalized for a period greater than one year	**40**	40	34

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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, 2011:

		Millions of Dollars			
			Suspended Since		
Project		Total	2008-2010	2005-2007	2001-2004
Aktote Kazakhstan[2]	$	19	-	-	19
Alpine Satellite Alaska[2]		21	-	-	21
Browse Basin Australia[1]		216	216	-	-
Caldita/Barossa Australia[1]		77	-	77	-
Fiord West Alaska[2]		16	16	-	-
Harrison U.K.[2]		15	-	15	-
Kairan Kazakhstan[2]		27	-	14	13
Kalamkas Kazakhstan[1]		14	5	5	4
Kashagan Kazakhstan[1]		44	19	15	10
Malikai Malaysia[2]		52	-	40	12
NPR-A Alaska[2]		17	17	-	-
Petai Malaysia[2]		30	19	11	-
Point Thomson Alaska[2]		37	37	-	-
Rak More Kazakhstan[1]		22	22	-	-
Saleski Canada[1]		14	14	-	-
Shenandoah Lower 48[1]		43	43	-	-
Sunrise 3 Australia[2]		13	13	-	-
Surmont III and beyond Canada[1]		26	6	18	2
Su tu Nau Vietnam[2]		18	9	9	-
Thornbury Canada[1]		19	19	-	-
Tiber Lower 48[1]		40	40	-	-
Titan Norway[2]		11	11	-	-
Ubah Malaysia[2]		34	34	-	-
Uge Nigeria[1]		29	15	14	-
Sixteen projects of $10 million or less each[1][2]		68	34	32	2
Total of 40 projects	$	922	589	250	83

(1) Additional appraisal wells planned.

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

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Note 9 Goodwill and Intangibles

Goodwill

Changes in the carrying amount of goodwill were as follows:

	Millions of Dollars					
	2011			2010		
	E&P	R&M	Total	E&P	R&M	Total
Balance as of January 1						
Goodwill	$ **25,443**	**3,633**	**29,076**	25,443	3,638	29,081
Accumulated impairment losses	**(25,443)**	**-**	**(25,443)**	(25,443)	-	(25,443)
	-	**3,633**	**3,633**	-	3,638	3,638
Goodwill allocated to assets held for sale or sold	**-**	**(273)**	**(273)**	-	-	-
Tax and other adjustments	**-**	**(28)**	**(28)**	-	(5)	(5)
Balance as of December 31						
Goodwill	**25,443**	**3,332**	**28,775**	25,443	3,633	29,076
Accumulated impairment losses	**(25,443)**	**-**	**(25,443)**	(25,443)	-	(25,443)
	$ **-**	**3,332**	**3,332**	-	3,633	3,633

Intangible Assets

Information at December 31 on the carrying value of intangible assets follows:

	Millions of Dollars Gross Carrying Amount	
	2011	2010
Indefinite-Lived Intangible Assets		
Trade names and trademarks	$ **494**	494
Refinery air and operating permits	**207**	245
	$ **701**	739

At year-end 2011, our amortized intangible asset balance was $44 million, compared with $62 million at year-end 2010. Amortization expense was not material for 2011 and 2010, and is not expected to be material in future years.

Note 10 Impairments

During 2011, 2010 and 2009, we recognized the following before-tax impairment charges:

	Millions of Dollars		
	2011	2010	2009
E&P			
United States	$ **72**	25	5
International	**216**	56	463
R&M			
United States	**470**	52	63
International	**2**	1,616	3
Emerging Businesses	**-**	31	-
Corporate	**32**	-	1
	$ **792**	1,780	535

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2011

In 2011, we recorded a $467 million impairment of our refinery and associated pipelines and terminals in Trainer, Pennsylvania. In September 2011, we announced plans to seek a buyer for the refinery and have idled the facility. If unable to sell the refinery, we expect to permanently close the plant by the end of the first quarter of 2012. Additionally, we recorded property impairments of $288 million in our E&P segment, primarily as a result of lower natural gas price assumptions and reduced volume forecasts.

2010

During 2010, we recorded a $1,514 million impairment of our refinery in Wilhelmshaven, Germany, due to canceled plans for a project to upgrade the refinery, as well as a $98 million impairment as a result of our decision to end our participation in a new refinery project in Yanbu Industrial City, Saudi Arabia. We also recorded various property impairments of $81 million in our E&P segment.

2009

During 2009, we recorded property impairments of $417 million in our E&P segment, primarily as a result of lower natural gas price assumptions, reduced volume forecasts, and higher royalty, operating costs and capital expenditure assumptions. Additionally, we recorded a noncash charge of $51 million before- and after-tax related to the full impairment of our exploration and production investments in Ecuador, due to their expropriation. An arbitration hearing on case merits occurred in March 2011, and the arbitration process is ongoing. Property impairments of $66 million in our R&M segment, primarily associated with planned asset dispositions, were also recorded during 2009.

Fair Value Remeasurements

The following table shows the values of assets, by major category, measured at fair value on a nonrecurring basis in periods subsequent to their initial recognition:

		Millions of Dollars		
		Fair Value Measurements Using		
	Fair Value*	Level 1 Inputs	Level 3 Inputs	Before-Tax Loss
Year ended December 31, 2011				
Net PP&E (held for use)	$ **162**	**-**	**162**	**265**
Equity method investments	**274**	**-**	**274**	**399**
Cost method investments	**2**	**2**	**-**	**8**
Year ended December 31, 2010				
Net PP&E (held for use)	$ 307	-	307	1,604**
Net PP&E (held for sale)	23	5	18	43
Equity method investments	735	-	735	645

**Represents the fair value at the time of the impairment.*

***Includes a $55 million leasehold impairment charged to exploration expenses.*

2011

During 2011, net PP&E held for use with a carrying amount of $427 million was written down to a fair value of $162 million, resulting in a before-tax loss of $265 million. The fair values were determined by the use of internal discounted cash flow models using estimates of future production, prices, costs and a discount rate believed to be consistent with those used by principal market participants and cash flow multiples for similar assets and alternative use.

Also during 2011, certain equity method investments were determined to have fair values below their carrying amount, and the impairments were considered to be other than temporary. This primarily included an investment associated with our E&P segment with a book value of $651 million, which was written down to its fair value of $256 million, resulting in a charge of $395 million before-tax. This was included in the Equity in earnings of affiliates line of our consolidated income statement. The fair value was determined by the application of an internal discounted cash flow model using estimates of future production, prices, costs and a

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discount rate believed to be consistent with those used by principal market participants. In addition, the fair value was determined by the comparison of market data for certain similar undeveloped properties.

2010

During 2010, net PP&E held for use with a carrying amount of $1,911 million was written down to a fair value of $307 million, resulting in a before-tax loss of $1,604 million. The fair values were determined by the use of internal discounted cash flow models using estimates of future production, prices, costs and a discount rate believed to be consistent with those used by principal market participants and cash flow multiples for similar assets and alternative use.

Also during 2010, net PP&E held for sale with a carrying amount of $64 million was written down to a fair value of $23 million less cost to sell of $2 million for a net $21 million, resulting in a before-tax loss of $43 million. The fair values were primarily determined by binding negotiated selling prices with third parties, with some adjusted for the fair value of certain liabilities retained.

In addition, an equity method investment associated with our E&P segment was determined to have a fair value below carrying amount, and the impairment was considered to be other than temporary. This investment with a book value of $1,380 million was written down to its fair value of $735 million, resulting in a charge of $645 million before-tax, which was included in the Equity in earnings of affiliates line of our consolidated income statement. The fair value was determined by the application of an internal discounted cash flow model using estimates of future production, prices, costs and a discount rate believed to be consistent with those used by principal market participants. In addition, the equity investment fair value was determined by the comparison of market data for certain similar undeveloped properties.

Note 11 Asset Retirement Obligations and Accrued Environmental Costs

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

		Millions of Dollars	
		2011	2010
Asset retirement obligations	$	**8,920**	8,776
Accrued environmental costs		**922**	994
Total asset retirement obligations and accrued environmental costs		**9,842**	9,770
Asset retirement obligations and accrued environmental costs due within one year*		**(513)**	(571)
Long-term asset retirement obligations and accrued environmental costs	$	**9,329**	9,199

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

Asset Retirement Obligations

We 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, we capitalize the associated asset retirement cost by increasing the carrying amount of the related PP&E. Over time, the liability increases for the change in its present value, while the capitalized cost depreciates over the useful life of the related asset.

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 plugging and abandonment of wells, 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.

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During 2011 and 2010, our overall asset retirement obligation changed as follows:

	Millions of Dollars	
	2011	2010
Balance at January 1	$ **8,776**	8,295
Accretion of discount	**435**	422
New obligations	**153**	64
Changes in estimates of existing obligations	**29**	744
Spending on existing obligations	**(327)**	(314)
Property dispositions	**(60)**	(394)
Foreign currency translation	**(86)**	(41)
Balance at December 31	$ **8,920**	8,776

Accrued Environmental Costs

Total accrued environmental costs at December 31, 2011 and 2010, were $922 million and $994 million, respectively. The 2011 decrease in total accrued environmental costs is due to payments and settlements during the year exceeding new accruals, accrual adjustments and accretion.

We had accrued environmental costs of $571 million and $624 million at December 31, 2011 and 2010, 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 $274 million and $278 million of environmental costs associated with nonoperator sites at December 31, 2011 and 2010, respectively. In addition, $77 million and $92 million were included at both December 31, 2011 and 2010, 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 are expected to 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 $427 million at December 31, 2011. The expected future undiscounted payments related to the portion of the accrued environmental costs that have been discounted are: $58 million in 2012, $44 million in 2013, $22 million in 2014, $19 million in 2015, $20 million in 2016, and $373 million for all future years after 2016.

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Note 12 Debt

Long-term debt at December 31 was:

		Millions of Dollars	
		2011	2010
9.375% Notes due 2011	$	**-**	328
9.125% Debentures due 2021		**150**	150
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		**7**	15
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% Debentures due 2029		**200**	200
6.95% Notes due 2029		**1,549**	1,549
6.875% Debentures due 2026		**67**	67
6.65% Debentures due 2018		**297**	297
6.50% Notes due 2011		**-**	500
6.50% Notes due 2039		**2,250**	2,250
6.50% Notes due 2039		**500**	500
6.00% Notes due 2020		**1,000**	1,000
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**	600
5.75% Notes due 2019		**2,250**	2,250
5.625% Notes due 2016		**1,250**	1,250
5.50% Notes due 2013		**750**	750
5.20% Notes due 2018		**500**	500
4.75% Notes due 2012		**897**	897
4.75% Notes due 2014		**1,500**	1,500
4.60% Notes due 2015		**1,500**	1,500
4.40% Notes due 2013		**400**	400
Commercial paper at 0.34% 0.341% at year-end 2011 and 0.14% 0.34% at year-end 2010		**1,128**	1,182
Industrial Development Bonds due 2012 through 2038 at 0.08% 5.75% at year-end 2011 and 0.33% 5.75% at year-end 2010		**252**	252
Guarantee of savings plan bank loan payable due 2015 at 2.29% at year-end 2011 and 2.06% at year-end 2010		**15**	64
Note payable to Merey Sweeny, L.P. due 2020 at 7% (related party)		**133**	144
Marine Terminal Revenue Refunding Bonds due 2031 at 0.08% 0.15% at year-end 2011 and 0.33% 0.48% at year-end 2010		**265**	265
Other		**28**	31
Debt at face value		**22,143**	23,096
Capitalized leases		**31**	39
Net unamortized premiums and discounts		**449**	457

Total debt		**22,623**	23,592
Short-term debt		**(1,013)**	(936)
Long-term debt	**$**	**21,610**	22,656

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Maturities of long-term borrowings, inclusive of net unamortized premiums and discounts, in 2012 through 2016 are: $1,013 million, $1,275 million, $1,527 million, $1,571 million and $2,364 million, respectively. At December 31, 2011, we classified $1,058 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.

During 2011, the following debt instruments were repaid at their maturity:

- The $328 million 9.375% Debentures due 2011.
- The $500 million 6.50% Notes due 2011.

In August 2011, we increased our revolving credit facilities from $7.85 billion to $8.0 billion by replacing our $7.35 billion revolving credit facility with a $7.5 billion facility expiring in August 2016. We also have a $500 million facility expiring in July 2012. Our revolving credit facilities may be used as direct bank borrowings, as support for issuances of letters of credit totaling up to $750 million, or as support for our commercial paper programs. 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.

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.

We have two commercial paper programs: the ConocoPhillips $6.35 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 QG3 Project. Commercial paper maturities are generally limited to 90 days. At both December 31, 2011 and 2010, we had no direct outstanding borrowings under the revolving credit facilities, but $40 million in letters of credit had been issued. In addition, under the two commercial paper programs, there was $1,128 million of commercial paper outstanding at December 31, 2011, compared with $1,182 million at December 31, 2010. Since we had $1,128 million of commercial paper outstanding and had issued $40 million of letters of credit, we had access to $6.8 billion in borrowing capacity under our revolving credit facilities at December 31, 2011.

Note 13 Joint Venture Acquisition Obligation

In 2007, we closed on a business venture with Cenovus. As a part of the transaction, we are obligated to contribute $7.5 billion, plus interest, over a 10-year period that began in 2007, to the upstream business venture, FCCL Partnership, formed as a result of the transaction.

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, $732 million was short-term and was included in the Accounts payable related parties line on our December 31, 2011, consolidated balance sheet. The principal portion of these payments, which totaled $695 million in 2011, is 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 payment is reflected as a capital contribution and is included in the Capital expenditures and investments line on our consolidated statement of cash flows.

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Note 14 Guarantees

At December 31, 2011, 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 billion in loan facilities of QG3, which are being used to finance the construction of an LNG train in Qatar. Of the $4 billion in loan facilities, we committed to provide $1.2 billion. Effective December 15, 2011, the project achieved financial completion, the financing became nonrecourse to ConocoPhillips and our guarantee was released.

Guarantees of Joint Venture Debt

At December 31, 2011, we had guarantees outstanding for our portion of joint venture debt obligations, which have terms of up to 24 years. The maximum potential amount of future payments under the guarantees is approximately $100 million. Payment would be required if a joint venture defaults on its debt obligations.

Other Guarantees

In conjunction with our purchase of an ownership interest in APLNG from Origin Energy in October 2008, we agreed to participate, if and when requested, in any parent company guarantees that were outstanding at the time we purchased our interest in APLNG. These parent company guarantees cover the obligation of APLNG to deliver natural gas under several sales agreements with remaining terms of 5 to 20 years. Our maximum potential amount of future payments, or cost of volume delivery, under these guarantees is estimated to be $1,261 million ($2,820 million in the event of intentional or reckless breach) at December 2011 exchange rates based on our 42.5 percent share of the remaining contracted volumes, which could become payable if APLNG fails to meet its obligations under these agreements and the obligations cannot otherwise be mitigated. Future payments are considered unlikely, as the payments, or cost of volume delivery, would only be triggered if APLNG does not have enough natural gas to meet these sales commitments and if the co-venturers do not make necessary equity contributions into APLNG. Additionally, we have guaranteed the performance of APLNG with regard to certain contracts executed in connection with APLNG s issuance of the Train 1 Notice to Proceed. Our maximum potential amount of future payments related to these guarantees is estimated to be $171 million at December 2011 exchange rates based on our 42.5 percent ownership in APLNG.

We have other guarantees with maximum future potential payment amounts totaling $450 million, which consist primarily of 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, guarantees of the residual value of leased corporate aircraft, and guarantees of the performance of a business partner or some of its customers. These guarantees generally extend up to 13 years or life of the venture.

Indemnifications

Over the years, we have entered into various agreements to sell ownership interests in certain corporations, joint ventures and assets 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, 2011, was $362 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 recorded carrying amount were $218 million of environmental accruals for known contamination that are included in asset retirement obligations and accrued environmental costs at December 31, 2011. For additional information about environmental liabilities, see Note 15 Contingencies and Commitments.

Note 15 Contingencies and Commitments

A number of lawsuits involving a variety of claims have been made against ConocoPhillips that arise in the ordinary course of business. We also may be required 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 active and inactive sites. We regularly assess the need for accounting recognition or disclosure of these contingencies. In the case of all known contingencies (other than those related to income taxes), 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 use a cumulative probability-weighted loss accrual in cases where sustaining a tax position is less than certain. See Note 20 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 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 international, federal, state and local environmental laws and regulations. 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 cleanup costs related to any site at which we have been designated as a potentially responsible party. 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,

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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 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 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 that have been scheduled for trial and/or mediation. 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 regularly assesses the adequacy of current accruals and determines if adjustment of existing accruals, or establishment of new accruals, is required.

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, 2011, we had performance obligations secured by letters of credit of $1,954 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.

In 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. As a result, Venezuela s national oil company, PDVSA, or its affiliates, directly assumed control over ConocoPhillips interests in the Petrozuata and Hamaca heavy oil ventures and the offshore Corocoro development project. In response to this expropriation, we filed a request for international arbitration on November 2, 2007, with the World Bank s International Centre for Settlement of Investment Disputes (ICSID). An arbitration hearing was held before an ICSID tribunal during the summer of 2010, and we are currently awaiting an interim decision on key legal and factual issues. A separate arbitration hearing was held in January 2012 before the International Chamber of Commerce on ConocoPhillips separate claims against PDVSA for certain breaches of their Association Agreements prior to the expropriation.

In 2008, Burlington Resources, Inc., a wholly owned subsidiary of ConocoPhillips, initiated arbitration before ICSID against The Republic of Ecuador, as a result of the newly enacted Windfall Profits Tax Law and government-mandated renegotiation of our production sharing contracts. Despite a restraining order issued by ICSID, Ecuador confiscated the crude oil production of Burlington and its co-venturer and sold the illegally seized crude oil. In 2009, Ecuador took over operations in Blocks 7 and 21, fully expropriating our assets. In June 2010, the ICSID tribunal concluded it has jurisdiction to hear the expropriation claim. An arbitration hearing on case merits occurred in March 2011. On September 30, 2011, Ecuador filed a supplemental counterclaim asserting environmental damages, which we believe will not be material. The arbitration process is ongoing. For additional information, see Note 10 Impairments.

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

We have certain throughput agreements and take-or-pay agreements 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: 2012 $468 million; 2013 $467 million; 2014 $467 million; 2015 $458 million; 2016 $364 million; and 2017 and after $4,890 million. Total payments under the agreements were $429 million in 2011, $216 million in 2010 and $114 million in 2009.

Note 16 Financial Instruments and Derivative Contracts

Financial Instruments

We invest excess cash in financial instruments with maturities based on our cash forecasts for the various currency pools we manage. The maturities of these investments may from time to time extend beyond 90 days. The types of financial instruments in which we currently invest include:

- Time Deposits: Interest bearing deposits placed with approved financial institutions.
- Commercial Paper: Unsecured promissory notes issued by a corporation, commercial bank, or government agency purchased at a discount, maturing at par.
- Government or government agency obligations: Negotiable debt obligations issued by a government or government agency.

These financial instruments appear in the Cash and cash equivalents line of our consolidated balance sheet if the maturities at the time we made the investments were 90 days or less; otherwise, these held-to-maturity investments are included in the Short-term investments line. At December 31, we held the following financial instruments:

	Millions of Dollars			
	Carrying Amount			
	Cash and Cash Equivalents		Short-Term Investments*	
	2011	2010	**2011**	2010
Cash	**$ 1,169**	1,284	**-**	-
Time Deposits				
Remaining maturities from 1 to 90 days	**4,318**	6,154	**349**	302
Remaining maturities from 91 to 180 days	**-**	-	**-**	69
Commercial Paper				
Remaining maturities from 1 to 90 days	**293**	1,566	**232**	525
Remaining maturities from 91 to 180 days	**-**	-	**-**	-
Government Obligations				
Remaining maturities from 1 to 90 days	**-**	450	**-**	77
Remaining maturities from 91 to 180 days	**-**	-	**-**	-
	$ 5,780	9,454	**581**	973

**Carrying value approximates fair value.*

Derivative Instruments

We use financial and commodity-based derivative contracts to manage exposures to fluctuations in foreign currency exchange rates, commodity prices, and interest rates, or to capture market opportunities. Since we are not currently using cash-flow hedge accounting, all gains and losses, realized or unrealized, from derivative contracts have been recognized in the consolidated income statement. Gains and losses from derivative contracts held for trading not directly related to our physical business, whether realized or unrealized, have been reported net in other income.

Purchase and sales contracts with fixed minimum notional volumes for commodities that are readily convertible to cash (e.g., crude oil, natural gas and gasoline) are recorded on the balance sheet as derivatives

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unless the contracts are eligible for and we elect the normal purchases and normal sales exception (i.e., contracts to purchase or sell quantities we expect to use or sell over a reasonable period in the normal course of business). We record most of our contracts to buy or sell natural gas and the majority of our contracts to sell power as derivatives, but we do apply the normal purchases and normal sales exception to certain long-term contracts to sell our natural gas production. We generally apply this normal purchases and normal sales exception to eligible crude oil and refined product commodity 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 sales contract but hedge accounting will not be applied, in which case both the purchase or sales contract and the derivative contract mitigating the resulting risk will be recorded on the balance sheet at fair value).

We value our exchange-traded 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. Where exchange-provided prices are adjusted, non-exchange quotes are used, or when the instrument lacks sufficient liquidity, we generally classify those exchange-cleared contracts as Level 2. Over-the-counter (OTC) financial swaps and physical commodity forward purchase and sales 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 sales 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. A contract that is initially classified as Level 3 due to absence or insufficient corroboration of broker quotes over a material portion of the contract will transfer to Level 2 when the portion of the trade having no quotes or insufficient corroboration becomes an insignificant portion of the contract. A contract would also transfer to Level 2 if we began using a corroborated broker quote that has become available. Conversely, if a corroborated broker quote ceases to be available or used by us, the contract would transfer from Level 2 to Level 3. There were no material transfers in or out of 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 options are classified as Level 2 or 3.

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 derivative assets and liabilities accounted for at fair value on a recurring basis was:

	Millions of Dollars							
	December 31, 2011				December 31, 2010			
	Level 1	Level 2	Level 3	Total	Level 1	Level 2	Level 3	Total
Assets								
Commodity derivatives*	**$ 2,807**	**1,947**	**72**	**4,826**	1,456	1,744	63	3,263
Interest rate derivatives	**-**	**31**	**-**	**31**	-	20	-	20
Foreign currency exchange derivatives	**-**	**13**	**-**	**13**	-	15	-	15
Total assets	**2,807**	**1,991**	**72**	**4,870**	1,456	1,779	63	3,298
Liabilities								
Commodity derivatives*	**2,970**	**1,722**	**10**	**4,702**	1,611	1,737	36	3,384
Foreign currency exchange derivatives	**-**	**23**	**-**	**23**	-	9	-	9
Total liabilities	**2,970**	**1,745**	**10**	**4,725**	1,611	1,746	36	3,393
Net assets (liabilities)	**$ (163)**	**246**	**62**	**145**	(155)	33	27	(95)

** 2010 has been reclassified to conform to current-year presentation.*

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The derivative values above are based on analysis of each contract as the fundamental unit of account; therefore, derivative assets and liabilities with the same counterparty are not reflected net where the right of setoff exists. 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.

As reflected in the table above, Level 3 activity was not material.

Commodity Derivative Contracts We operate in the worldwide crude oil, bitumen, refined product, natural gas, LNG, 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, we use futures, forwards, swaps and options in various markets to balance physical systems, meet customer needs, manage price exposures on specific transactions, and do a limited, immaterial amount of trading not directly related to our physical business. We also use the market knowledge gained from these activities to capture market opportunities such as moving physical commodities to more profitable locations, storing commodities to capture seasonal or time premiums, and blending commodities to capture quality upgrades. Derivatives may be used to optimize these activities which may move our risk profile away from market average prices.

The fair value of commodity derivative assets and liabilities and the line items where they appear on our consolidated balance sheet were:

	Millions of Dollars	
	2011	2010
Assets		
Prepaid expenses and other current assets	**$ 4,433**	3,073
Other assets	**415**	211
Liabilities		
Other accruals	**4,350**	3,212
Other liabilities and deferred credits	**374**	193

Hedge accounting has not been used for any item in the table. The amounts shown are presented gross (i.e., without netting assets and liabilities with the same counterparty where the right of setoff exists).

The gains (losses) from commodity derivatives incurred, and the line items where they appear on our consolidated income statement were:

	Millions of Dollars		
	2011	2010	2009
Sales and other operating revenues*	**$ 302**	(1,243)	1,167
Other income	**3**	(38)	19
Purchased crude oil, natural gas and products*	**(596)**	1,127	(1,823)

**2010 and 2009 have been restated to eliminate certain non-derivative transactions and realign certain derivative transactions between sales and purchases.*

Hedge accounting has not been used for any item in the table.

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The table below summarizes our material net exposures resulting from outstanding commodity derivative contracts. These financial and physical derivative contracts are primarily used to manage price exposures on our underlying operations. The underlying exposures may be from non-derivative positions such as inventory volumes or firm natural gas transport contracts. Financial derivative contracts may also offset physical derivative contracts, such as forward sales contracts.

	Open Position Long / (Short)	
	2011	2010
Commodity		
Crude oil, refined products and natural gas liquids (millions of barrels)	**(13)**	(16)
Natural gas and power (billions of cubic feet equivalent)		
Fixed price	**(57)**	(69)
Basis	**(25)**	(43)

Interest Rate Derivative Contracts During the second quarter of 2010, we executed interest rate swaps to synthetically convert $500 million of our 4.60% fixed-rate notes due in 2015 to a floating rate based on the London Interbank Offered Rate (LIBOR). These swaps qualify for and are designated as fair-value hedges using the short-cut method of hedge accounting. The short-cut method permits the assumption that changes in the value of the derivative perfectly offset changes in the value of the debt; therefore, no gain or loss has been recognized due to hedge ineffectiveness.

The adjustments to the fair values of the interest rate swaps and hedged debt have not been material.

Foreign Currency Exchange Derivatives We have foreign currency exchange rate risk resulting from international operations. We do not comprehensively hedge the exposure to movements in currency exchange rates, although we may choose to selectively hedge certain foreign currency exchange rate exposures, such as firm commitments for capital projects or local currency tax payments, dividends, and cash returns from net investments in foreign affiliates to be remitted within the coming year.

The fair value of foreign currency exchange derivative assets and liabilities, and the line items where they appear on our consolidated balance sheet were:

	Millions of Dollars	
	2011	2010
Assets		
Prepaid expenses and other current assets	**$ 12**	14
Other assets	**1**	1
Liabilities		
Other accruals	**23**	7
Other liabilities and deferred credits	**-**	2

Hedge accounting has not been used for any item in the table. The amounts shown are presented gross.

Gains and losses from foreign currency exchange derivatives and the line item where they appear on our consolidated income statement were:

Millions of Dollars

	2011	2010	2009
Foreign currency transaction (gains) losses	**$ (14)**	118	(121)

Hedge accounting has not been used for any item in the table.

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We had the following net notional position of outstanding foreign currency exchange derivatives:

		In Millions	
		Notional Currency *	
		2011	2010
Foreign Currency Exchange Derivatives			
Sell U.S. dollar, buy other currencies**	USD	**1,949**	569
Sell euro, buy other currencies***	EUR	**61**	253

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

***Primarily euro, Canadian dollar, Norwegian krone and British pound.*

****Primarily Norwegian krone and British pound.*

Credit Risk

Financial instruments potentially exposed to concentrations of credit risk consist primarily of cash equivalents, OTC derivative contracts and trade receivables. Our cash equivalents and short-term investments are placed in high-quality commercial paper, money market funds, government debt securities and time deposits with major international banks and financial institutions.

The credit risk from our OTC derivative contracts, such as forwards and swaps, derives from the counterparty to the transaction. Individual counterparty exposure is managed within predetermined credit limits and includes the use of cash-call margins when appropriate, thereby reducing the risk of significant nonperformance. We also use futures, swaps and option contracts that have a negligible credit risk because these trades are cleared with an exchange clearinghouse and subject to mandatory margin requirements until settled; however, we are exposed to the credit risk of those exchange brokers for receivables arising from daily margin cash calls, as well as for cash deposited to meet initial margin requirements.

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.

Certain of our derivative instruments contain provisions that require us to post collateral if the derivative exposure exceeds a threshold amount. We have contracts with fixed threshold amounts and other contracts with variable threshold amounts that are contingent on our credit rating. The variable threshold amounts typically decline for lower credit ratings, while both the variable and fixed threshold amounts typically revert to zero if we fall below investment grade. Cash is the primary collateral in all contracts; however, many also permit us to post letters of credit as collateral.

The aggregate fair value of all derivative instruments with such credit-risk-related contingent features that were in a liability position on December 31, 2011, was $237 million, for which $3 million of collateral was posted. If our credit rating were lowered one level from its A rating (per Standard and Poor s) on December 31, 2011, we would be required to post no additional collateral to our counterparties. If we were downgraded below investment grade, we would be required to post $234 million of additional collateral, either with cash or letters of credit.

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Fair Values of Financial Instruments

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

Cash, cash equivalents and short-term investments: 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: We completed the disposition of our interest in LUKOIL during the first quarter of 2011. At December 31, 2010, our investment in LUKOIL was carried at fair value of $1,083 million, reflecting a closing price of LUKOIL ADRs on the London Stock Exchange of $56.50 per share.
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 December 31, 2011, and December 31, 2010, using effective yield rates of 1.24 percent and 1.87 percent, respectively, 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.
Commodity swaps: Fair value is estimated based on forward market prices and approximates the exit price at period end. When forward market prices are not available, fair value is estimated using the forward prices of a similar commodity with adjustments for differences in quality or location.
Futures: Fair values are based on quoted market prices obtained from the New York Mercantile Exchange, the IntercontinentalExchange (ICE) Futures, or other traded exchanges.
Interest rate swap contracts: Fair value is estimated based on a pricing model and market-observable interest rate swap curves obtained from a third-party market data provider.
Forward-exchange contracts: Fair values are estimated by comparing the contract rate to the forward rates in effect at the end of the respective reporting periods, and approximate the exit prices at those dates.

Our commodity derivative and financial instruments were:

	Millions of Dollars			
	Carrying Amount		Fair Value	
	2011	2010	**2011**	2010
Financial Assets				
Foreign currency exchange derivatives	**$ 13**	15	**13**	15
Interest rate derivatives	**31**	20	**31**	20
Commodity derivatives	**814**	624	**814**	624
Investment in LUKOIL	**-**	1,083	**-**	1,083
Financial Liabilities				
Total debt, excluding capital leases	**22,592**	23,553	**27,065**	26,144
Joint venture acquisition obligation	**4,314**	5,009	**4,820**	5,600
Foreign currency exchange derivatives	**23**	9	**23**	9
Commodity derivatives	**446**	426	**446**	426

The amounts shown for derivatives in the preceding table are presented net (i.e., assets and liabilities with the same counterparty are netted where the right of setoff exists). In addition, the December 31, 2011, commodity derivative assets and liabilities appear net of no obligations to return cash collateral and $244 million of rights to reclaim cash collateral. The December 31, 2010, commodity derivative assets and liabilities appear net of $5 million of obligations to return cash collateral and $324 million of rights to reclaim cash collateral, respectively. No collateral was deposited or held for the foreign currency derivatives or interest rate derivatives.

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Note 17 Equity

Common Stock

The changes in our shares of common stock, as categorized in the equity section of the balance sheet, were:

	Shares		
	2011	2010	2009
Issued			
Beginning of year	**1,740,529,279**	1,733,345,558	1,729,264,859
Distributed under benefit plans	**9,021,308**	7,183,721	4,080,699
End of year	**1,749,550,587**	1,740,529,279	1,733,345,558
Held in Treasury			
Beginning of year	**272,873,537**	208,346,815	208,346,815
Repurchase of common stock	**155,453,382**	64,526,722	-
Distributed under benefit plans	**(475,696)**	-	-
Transfer from grantor trust	**36,029,405**	-	-
End of year	**463,880,628**	272,873,537	208,346,815
Held in Grantor Trusts			
Beginning of year	**36,890,375**	38,742,261	40,739,129
Repurchase of common stock	**(157,470)**	-	-
Distributed under benefit plans	**(703,500)**	(1,776,873)	(2,018,692)
Transfer to treasury stock	**(36,029,405)**	-	-
Other	**-**	(75,013)	21,824
End of year	**-**	36,890,375	38,742,261

Preferred Stock

We have authorized 500 million shares of preferred stock, par value $.01 per share, none of which was issued or outstanding at December 31, 2011 or 2010.

Noncontrolling Interests

At December 31, 2011 and 2010, we had outstanding $510 million and $547 million, respectively, of equity in less-than-wholly owned consolidated subsidiaries held by noncontrolling interest owners. The noncontrolling interest amounts are primarily related to operating joint ventures we control. The largest of these, amounting to $482 million and $520 million at December 31, 2011, and 2010, respectively, was related to Darwin LNG operations, located in Australia s Northern Territory.

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 acquirer 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 acquirer obtains 15 percent or more of ConocoPhillips common stock, then each right will be adjusted so that it will entitle the holder (other than the acquirer, 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.

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Note 18 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 with regard to dividends, asset dispositions or borrowing ability. Leased assets under capital leases were not significant in any period presented.

At December 31, 2011, future minimum rental payments due under noncancelable leases were:

	Millions of Dollars
2012	$ 767
2013	519
2014	382
2015	300
2016	202
Remaining years	591
Total	2,761
Less income from subleases	132*
Net minimum operating lease payments	$ 2,629

**Includes $64 million related to subleases to related parties.*

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

	Millions of Dollars		
	2011	2010	2009
Total rentals*	**$ 901**	925	1,024
Less sublease rentals	**(32)**	(34)	(34)
	$ 869	891	990

**Includes $35 million, $22 million and $21 million of contingent rentals in 2011, 2010 and 2009, respectively. Contingent rentals primarily are related to drilling equipment and retail sites, and are based on usage or volume of product sold.*

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Note 19 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	
		2011		2010		**2011**	2010
		U.S.	**Int l.**	U.S.	Int l.		
Change in Benefit Obligation							
Benefit obligation at January 1	$	**5,539**	**3,206**	5,042	3,101	**862**	839
Service cost		**225**	**98**	229	90	**10**	11
Interest cost		**247**	**178**	260	169	**42**	46
Plan participant contributions		**-**	**5**	-	4	**23**	20
Government subsidy		**-**	**-**	-	-	**4**	-
Plan amendments		**-**	**(53)**	12	-	**35**	-
Actuarial loss		**642**	**195**	305	59	**20**	14
Benefits paid		**(478)**	**(116)**	(309)	(115)	**(68)**	(70)
Curtailment		**-**	**-**	-	(1)	**-**	-
Foreign currency exchange rate change		**-**	**(29)**	-	(101)	**(2)**	2
Benefit obligation at December 31*	$	**6,175**	**3,484**	5,539	3,206	**926**	862
**Accumulated benefit obligation portion of above at December 31:*	*$*	***5,363***	***2,939***	*4,905*	*2,711*		
Change in Fair Value of Plan Assets							
Fair value of plan assets at January 1	$	**3,890**	**2,581**	3,144	2,281	**-**	-
Actual return on plan assets		**64**	**53**	458	259	**-**	-
Company contributions		**673**	**226**	597	216	**41**	50
Plan participant contributions		**-**	**5**	-	4	**23**	20
Government subsidy		**-**	**-**	-	-	**4**	-
Benefits paid		**(478)**	**(116)**	(309)	(115)	**(68)**	(70)
Curtailment		**-**	**-**	-	(1)	**-**	-
Foreign currency exchange rate change		**-**	**(27)**	-	(63)	**-**	-
Fair value of plan assets at December 31	$	**4,149**	**2,722**	3,890	2,581	**-**	-
Funded Status	$	**(2,026)**	**(762)**	(1,649)	(625)	**(926)**	(862)

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	$(2,026)	**$(2,026)**	**$(2,026)**	**$(2,026)**	**$(2,026)**	**$(2,026)**
	Millions of Dollars					
	Pension Benefits				Other Benefits	
	2011		2010		**2011**	2010
	U.S.	**Int l.**	U.S.	Int l.		
Amounts Recognized in the Consolidated Balance Sheet at December 31						
Noncurrent assets	$ **-**	**94**	-	156	**-**	-
Current liabilities	**(118)**	**(5)**	(74)	(4)	**(62)**	(51)
Noncurrent liabilities	**(1,908)**	**(851)**	(1,575)	(777)	**(864)**	(811)
Total recognized	$ **(2,026)**	**(762)**	(1,649)	(625)	**(926)**	(862)
	$(2,026)	**$(2,026)**	**$(2,026)**	**$(2,026)**	**$(2,026)**	**$(2,026)**
Weighted-Average Assumptions Used to Determine Benefit Obligations at December 31						
Discount rate	**4.30%**	**4.90**	4.65	5.40	**4.40**	5.00
Rate of compensation increase	**4.25**	**4.30**	4.00	4.10	**-**	-
Weighted-Average Assumptions Used to Determine Net Periodic Benefit Cost for Years Ended December 31						
Discount rate	**4.65%**	**5.40**	5.35	5.80	**5.00**	5.60
Expected return on plan assets	**7.00**	**6.40**	7.00	6.50	**-**	-
Rate of compensation increase	**4.00**	**4.10**	4.00	4.50	**-**	-

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.

Included in accumulated other comprehensive income at December 31 were the following before-tax amounts that had not been recognized in net periodic benefit cost:

	$(2,026)	**$(2,026)**	**$(2,026)**	**$(2,026)**	**$(2,026)**	**$(2,026)**
	Millions of Dollars					
	Pension Benefits				Other Benefits	
	2011		2010		**2011**	2010
	U.S.	**Int l.**	U.S.	Int l.		
Unrecognized net actuarial loss (gain)	$ **2,240**	**705**	1,567	444	**(26)**	(51)
Unrecognized prior service cost (credit)	**52**	**(78)**	61	(25)	**(13)**	(54)

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	Millions of Dollars					
	Pension Benefits				Other Benefits	
	2011		2010		**2011**	2010
	U.S.	**Int l.**	U.S.	Int l.		
Sources of Change in Other Comprehensive Income						
Net gain (loss) arising during the period	**$ (858)**	**(307)**	(70)	75	**(20)**	(14)
Amortization of (gain) loss included in income	**185**	**46**	167	55	**(5)**	(7)
Net change during the period	**$ (673)**	**(261)**	97	130	**(25)**	(21)
Prior service (cost) credit arising during the period	**$ -**	**53**	(12)	(1)	**(34)**	-
Amortization of prior service cost (credit) included in income	**9**	**-**	10	2	**(7)**	3
Net change during the period	**$ 9**	**53**	(2)	1	**(41)**	3

Amounts included in accumulated other comprehensive income at December 31, 2011, that are expected to be amortized into net periodic postretirement cost during 2012 are provided below:

	Millions of Dollars		
	Pension Benefits		Other Benefits
	U.S.	Int l.	
Unrecognized net actuarial loss (gain)	$ 235	71	(3)
Unrecognized prior service cost	9	(9)	(4)

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 $8,481 million, $7,377 million, and $6,098 million, respectively, at December 31, 2011, and $7,661 million, $6,718 million, and $5,706 million, respectively, at December 31, 2010.

For our unfunded nonqualified key employee supplemental pension plans, the projected benefit obligation and the accumulated benefit obligation were $499 million and $374 million, respectively, at December 31, 2011, and were $479 million and $407 million, respectively, at December 31, 2010.

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		
	2011		2010		2009		**2011**	2010	2009
	U.S.	**Int l.**	U.S.	Int l.	U.S.	Int l.			
Components of Net Periodic Benefit Cost									
Service cost	**$ 225**	**98**	229	90	194	79	**10**	11	9
Interest cost	**247**	**178**	260	169	277	144	**42**	46	47

Expected return on plan assets	**(280)**	**(175)**	(224)	(147)	(184)	(125)	**-**	-	-
Amortization of prior service cost (credit)	**9**	**-**	10	2	11	1	**(7)**	3	9
Recognized net actuarial loss (gain)	**165**	**46**	167	55	186	35	**(5)**	(7)	(15)
Net periodic benefit cost	**$ 366**	**147**	442	169	484	134	**40**	53	50

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We recognized pension settlement losses of $21 million in 2011 and $15 million in 2009. None were recognized in 2010.

We recognized special termination benefits of $5 million in 2009. None were recognized in 2011 and 2010.

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 actuarial 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 7.75 percent in 2012 that declines to 5 percent by 2023. A one-percentage-point change in the assumed health care cost trend rate would be immaterial to ConocoPhillips.

Plan Assets We follow a policy of broadly diversifying pension plan assets across asset classes, investment managers, and individual holdings. As a result, our plan assets have no significant concentrations of credit risk. 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. The target allocations for plan assets are 56 percent equity securities, 35 percent debt securities, 6 percent real estate and 3 percent in all other types of investments. Generally, the investments in the plans are publicly traded, therefore minimizing liquidity risk in the portfolio.

Following is a description of the valuation methodologies used for the pension plan assets. There have been no changes in the methodologies used at December 31, 2011 and 2010.

- Fair values of equity securities and government debt securities categorized in Level 1 are primarily based on quoted market prices.

- Fair values of corporate debt securities, agency and mortgage-backed securities and government debt securities categorized in Level 2 are estimated using recently executed transactions and market price quotations. If there have been no market transactions in a particular fixed income security, its fair market value is calculated by pricing models that benchmark the security against other securities with actual market prices. When observable price quotations are not available, fair value is based on pricing models that use something other than actual market prices (e.g., observable inputs such as benchmark yields, reported trades and issuer spreads for similar securities), and these securities are categorized in Level 3 of the fair value hierarchy.

- Fair values of investments in common/collective trusts are determined by the issuer of each fund based on the fair value of the underlying assets.

- Fair values of mutual funds are valued based on quoted market prices, which represent the net asset value of shares held.

- Cash is valued at cost, which approximates fair value. Fair values of cash equivalents categorized in Level 2 are valued using observable yield curves, discounting and interest rates.

- Fair values of exchange-traded derivatives classified in Level 1 are based on quoted market prices. For other derivatives classified in Level 2, the values are generally calculated from pricing models with market input parameters from third-party sources.

- Private equity funds are valued at net asset value as determined by the issuer based on the fair value of the underlying assets.

Fair values of insurance contracts are valued at the present value of the future benefit payments owed by the insurance company to the Plans participants.

Fair values of real estate investments are valued using real estate valuation techniques and other methods that include reference to third-party sources and sales comparables where available.

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. The participation interest is classified as Level 3 in the fair value hierarchy as the fair value is determined via a combination of comparison to quoted market prices and estimation using recently executed transactions and market price quotations for contract assets, and an actuarial present value computation for contract obligations. At December 31, 2011, the participating interest in the annuity contract was valued at $144 million and consisted of $391 million in debt securities, less $247 million for the accumulated benefit obligation covered by the contract. At December 31, 2010, the participating interest in the annuity contract was valued at $92 million and consisted of $357 million in debt securities, less $265 million for the accumulated benefit obligation covered by the contract. The net change from 2010 to 2011 is due to an increase in the fair market value of the underlying investments of $34 million and a decrease in the present value of the contract obligation of $18 million. 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.

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The fair values of our pension plan assets at December 31, by asset class were as follows:

	$ 2,365	$ 2,365	$ 2,365	$ 2,365	$ 2,365	$ 2,365	$ 2,365	$ 2,365
				Millions of Dollars				
		U.S.				International		
	Level 1	Level 2	Level 3	Total	Level 1	Level 2	Level 3	Total
2011								
Equity Securities								
U.S.	**$ 1,251**	**-**	**-**	**1,251**	**413**	**-**	**-**	**413**
International	**803**	**-**	**-**	**803**	**413**	**-**	**-**	**413**
Common/collective trusts	**-**	**634**	**-**	**634**	**-**	**234**	**-**	**234**
Mutual funds	**-**	**-**	**-**	**-**	**246**	**-**	**-**	**246**
Debt Securities								
Government	**311**	**81**	**-**	**392**	**532**	**-**	**-**	**532**
Corporate	**-**	**551**	**3**	**554**	**-**	**122**	**1**	**123**
Agency and mortgage-backed securities	**-**	**105**	**-**	**105**	**-**	**43**	**-**	**43**
Common/collective trusts	**-**	**249**	**-**	**249**	**-**	**346**	**-**	**346**
Mutual funds	**-**	**-**	**-**	**-**	**130**	**-**	**-**	**130**
Cash and cash equivalents	**-**	**-**	**-**	**-**	**32**	**26**	**-**	**58**
Private equity funds	**-**	**-**	**4**	**4**	**-**	**-**	**13**	**13**
Derivatives	**-**	**-**	**-**	**-**	**-**	**11**	**-**	**11**
Insurance contracts	**-**	**-**	**-**	**-**	**-**	**-**	**15**	**15**
Real estate	**-**	**-**	**-**	**-**	**-**	**-**	**139**	**139**
Total*	**$ 2,365**	**1,620**	**7**	**3,992**	**1,766**	**782**	**168**	**2,716**

**Excludes the participating interest in the annuity contract with a net asset value of $144 million and net receivables related to security transactions of $19 million.*

	$ 2,365	$ 2,365	$ 2,365	$ 2,365	$ 2,365	$ 2,365	$ 2,365	$ 2,365
2010								
Equity Securities								
U.S.	$ 1,250	-	-	1,250	378	-	-	378
International	818	-	-	818	498	-	-	498
Common/collective trusts	-	635	-	635	-	246	-	246
Mutual funds	-	-	-	-	282	-	-	282
Debt Securities								
Government	251	56	-	307	390	-	-	390
Corporate	-	420	3	423	-	171	2	173
Agency and mortgage-backed securities	-	81	-	81	-	-	-	-
Common/collective trusts	-	270	-	270	-	329	-	329
Mutual funds	-	-	-	-	122	-	-	122
Cash and cash equivalents	-	-	-	-	9	10	-	19
Private equity funds	-	-	6	6	-	-	8	8
Derivatives	-	-	-	-	-	12	-	12
Insurance contracts	-	-	-	-	-	-	16	16
Real estate	-	-	-	-	-	-	101	101

Total*	$	2,319	1,462	9	3,790	1,679	768	127	2,574

**Excludes the participating interest in the annuity contract with a net asset value of $92 million and net receivables related to security transactions of $15 million.*

As reflected in the table above, Level 3 activity was not material.

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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 2012, we expect to contribute approximately $690 million to our domestic qualified and nonqualified pension and postretirement benefit plans and $235 million to our international qualified and nonqualified pension and postretirement benefit plans.

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.	
2012	$ 577	110	63
2013	501	113	64
2014	524	121	67
2015	553	129	70
2016	598	134	72
2017-2021	3,206	794	385

Defined Contribution Plans

Most U.S. employees are eligible to participate in the ConocoPhillips Savings Plan (CPSP). Employees can deposit up to 75 percent of their eligible pay up to the statutory limit ($16,500 in 2011) in the thrift feature of the CPSP to a choice of approximately 39 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 $25 million in 2011, $24 million in 2010, and $23 million in 2009.

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 2012 through 2014, 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.

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 $77 million, $92 million and $83 million in 2011, 2010 and 2009, respectively, all of which was compensation expense. In 2011, we made cash contributions to the CPSP of $4 million. No cash contributions were made in 2010 and 2009. In 2011, 2010 and 2009, we contributed 660,755 shares, 1,776,873 shares and 2,018,692 shares, respectively, of company common stock from the Compensation and Benefits Trust. The shares had a fair market value of $84 million, $103 million and $94 million, respectively. Also in 2011, we contributed 475,696 shares of company common stock from Treasury stock. Dividends used to service debt were $45 million, $41 million and $39 million in 2011, 2010 and 2009, respectively. These dividends reduced the amount of compensation expense recognized each period. Interest incurred on the CPSP debt in 2011, 2010 and 2009 was $1 million, $2 million and $2 million, respectively.

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

	2011	2010
Unallocated shares	**811,963**	3,385,778
Allocated shares	**19,315,372**	19,198,502
Total shares	**20,127,335**	22,584,280

The fair value of unallocated shares at December 31, 2011 and 2010, was $59 million and $231 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 $56 million in 2011, $52 million in 2010 and $51 million in 2009.

Share-Based Compensation Plans

The 2011 Omnibus Stock and Performance Incentive Plan of ConocoPhillips (the Plan) was approved by shareholders in May 2011. Over its 10-year life, the Plan allows the issuance of up to 100 million shares of our common stock for compensation to our employees, directors and consultants; however, as of the effective date of the Plan, (i) any shares of common stock available for future awards under the prior plans and (ii) any shares of common stock represented by awards granted under the prior plans that are forfeited, expire or are canceled without delivery of shares of common stock or which result in the forfeiture of shares of common stock back to the company shall be available for awards under the Plan, and no new awards shall be granted under the prior plans. Of the 100 million shares available for issuance under the Plan, no more than 40 million shares of common stock are available for incentive stock options, and no more than 40 million shares are available 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 Statement of Financial Accounting Standards No. 123(R), codified into FASB ASC Topic 718, Compensation Stock Compensation, 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 ASC 718 on January 1, 2006, we recognize share-based compensation expense over the shorter of the service period (i.e., the stated period of time required to earn the award); or 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 ASC 718 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 ASC 718, 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.

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

	Millions of Dollars		
	2011	2010	2009
Compensation cost	**$ 246**	211	121
Tax benefit	**86**	78	42

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, 2011:

	Options	Weighted-Average Exercise Price	Weighted-Average Grant-Date Fair Value	Millions of Dollars Aggregate Intrinsic Value
Outstanding at December 31, 2008	36,615,753	$ 35.65		
Granted	3,311,200	45.47	$ 11.18	
Exercised	(2,919,118)	24.10		$ 67
Forfeited	(332,941)	52.04		
Expired or canceled	(241,421)	63.49		
Outstanding at December 31, 2009	36,433,473	$ 37.13		
Granted	3,040,500	48.39	$ 11.70	
Exercised	(6,401,483)	29.08		$ 183
Forfeited	(255,889)	48.42		
Expired or canceled	(204,727)	58.94		
Outstanding at December 31, 2010	32,611,874	$ 39.54		
Granted	**1,907,000**	**70.13**	**$ 16.70**	
Exercised	**(10,022,685)**	**30.08**		**$ 416**
Forfeited	**(82,434)**	**62.26**		
Expired or canceled	**(41,704)**	**51.60**		
Outstanding at December 31, 2011	**24,372,051**	**$ 45.73**		
Vested at December 31, 2011	**22,214,254**	**$ 44.49**		**$ 611**
Exercisable at December 31, 2011	**19,666,959**	**$ 43.19**		**$ 564**

The weighted-average remaining contractual term of vested options and exercisable options at December 31, 2011, was 3.95 years and 3.4 years, respectively.

During 2011, we received $197 million in cash and realized a tax benefit of $119 million from the exercise of options. At December 31, 2011, the remaining unrecognized compensation expense from unvested options was $16 million, which will be recognized over a weighted-average period of 19 months, the longest period being 25 months.

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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:

	2011	2011	2011
	2011	2010	2009
Assumptions used			
Risk-free interest rate	**3.10%**	3.23	2.90
Dividend yield	**4.00%**	4.00	3.50
Volatility factor	**33.40%**	33.80	32.90
Expected life (years)	**6.87**	6.65	6.53

The ranges in the assumptions used were as follows:

33.40 33.40 33.40 33.40 33.40 33.40 33.40 33.40

	2011		2010		2009	
	High	**Low**	High	Low	High	Low
Ranges used						
Risk-free interest rate	**3.10%**	**3.10**	3.23	3.23	2.90	2.90
Dividend yield	**4.00**	**4.00**	4.00	4.00	3.50	3.50
Volatility factor	**33.40**	**33.40**	33.80	33.80	32.90	32.90

We calculate volatility using the most recent ConocoPhillips end-of-week closing stock prices spanning a period equal to 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 Generally, restricted stock units are granted annually under the provisions of the Plan and 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. In addition to these regularly scheduled annual awards, restricted stock units are also granted ad hoc to attract or retain key personnel, and the terms and conditions under which these restricted stock units vest vary by award. 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.

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The following summarizes our stock unit activity for the three years ended December 31, 2011:

	Stock Units	Weighted-Average Grant-Date Fair Value	Millions of Dollars Total Fair Value
Outstanding at December 31, 2008	5,927,698	$ 61.14	
Granted	2,910,095	43.41	
Forfeited	(207,932)	51.84	
Issued	(1,910,309)		$ 88
Outstanding at December 31, 2009	6,719,552	$ 57.08	
Granted	2,890,010	46.38	
Forfeited	(233,212)	53.11	
Issued	(1,573,487)		$ 79
Outstanding at December 31, 2010	7,802,863	$ 53.04	
Granted	**2,746,045**	**67.54**	
Forfeited	**(299,531)**	**56.43**	
Issued	**(1,520,419)**		**$ 109**
Outstanding at December 31, 2011	**8,728,958**	**$ 55.41**	
Not Vested at December 31, 2011	**6,175,477**	**$ 55.93**	

At December 31, 2011, the remaining unrecognized compensation cost from the unvested units was $188 million, which will be recognized over a weighted-average period of 30 months, the longest period being 100 months.

Performance Share Program Under the Plan, we also annually grant to senior management restricted performance share units (PSUs) that do not vest until either (i) with respect to awards for performance 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 performance 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 PSUs 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 PSUs are settled by issuing one share of ConocoPhillips common stock per unit. Until issued as stock, recipients of the PSUs receive a quarterly cash payment of a dividend equivalent that is charged to expense. In its current form, the first grant of PSUs under this program was in 2006.

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The following summarizes our Performance Share Program activity for the three years ended December 31, 2011:

	Performance Share Units	Weighted-Average Grant-Date Fair Value	Millions of Dollars Total Fair Value
Outstanding at December 31, 2008	3,176,178	$ 68.13	
Granted	659,812	45.47	
Forfeited	(23,670)	65.00	
Issued	(407,442)		$ 19
Outstanding at December 31, 2009	3,404,878	$ 64.63	
Granted	317,072	48.39	
Forfeited	(53,243)	62.66	
Issued	(234,121)		$ 12
Outstanding at December 31, 2010	3,434,586	$ 63.43	
Granted	**615,780**	**70.57**	
Forfeited	**(23,240)**	**63.18**	
Issued	**(509,365)**		**$ 37**
Outstanding at December 31, 2011	**3,517,761**	**$ 64.35**	
Not Vested at December 31, 2011	**1,063,982**	**$ 64.16**	

At December 31, 2011, the remaining unrecognized compensation cost from unvested Performance Share awards was $27 million, which will be recognized over a weighted-average period of 46 months, the longest period being 15 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.

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The following summarizes the aggregate activity of these restricted shares and units for the three years ended December 31, 2011:

	Stock Units	Weighted-Average Grant-Date Fair Value	Millions of Dollars Total Fair Value
Outstanding at December 31, 2008	3,364,020	$ 36.75	
Granted	78,299	45.72	
Issued	(204,160)		$ 10
Canceled	(101,642)	52.91	
Outstanding at December 31, 2009	3,136,517	$ 35.11	
Granted	73,395	53.33	
Issued	(181,035)		$ 9
Canceled	(58,441)	44.23	
Outstanding at December 31, 2010	2,970,436	$ 34.06	
Granted	**76,642**	**70.25**	
Issued	**(139,523)**		**$ 10**
Canceled	**(319,640)**	**30.90**	
Outstanding at December 31, 2011	**2,587,915**	**$ 33.49**	
Not Vested at December 31, 2011	**-**		

At December 31, 2011, there was no remaining unrecognized compensation cost from the unvested units.

Compensation and Benefits Trust

The Compensation and Benefits Trust (CBT) was 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 trustee voted 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 was consolidated by ConocoPhillips; therefore, the cash contribution and promissory note were eliminated in consolidation. Shares held by the CBT were valued at cost and did not affect earnings per share or total common stockholders equity until after they were transferred out of the CBT. In 2010, 1,776,873 shares were transferred out of the CBT.

In August 2011, all of the approximately 36 million shares of company common stock held by the CBT were transferred to ConocoPhillips, and those shares are now held as non-voting treasury stock. Because the CBT was consolidated by us, the transfer of its shares from Grantor trusts to Treasury stock in the equity section of our balance sheet was recorded at the shares historical carrying value of $610 million. This transfer did not affect total equity, shares outstanding, or earnings per share. The CBT no longer holds any assets. Two smaller grantor trusts also disposed of all their shares of company stock during 2011.

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Note 20 Income Taxes

Income taxes charged to income were:

	Millions of Dollars		
	2011	2010	2009
Income Taxes			
Federal			
Current	$ **1,917**	1,312	575
Deferred	**943**	781	52
Foreign			
Current	**7,095**	7,469	5,584
Deferred	**(2)**	(1,546)	(1,245)
State and local			
Current	**413**	320	82
Deferred	**133**	(3)	42
	$ **10,499**	8,333	5,090

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	
	2011	2010
Deferred Tax Liabilities		
PP&E and intangibles	$ **21,159**	20,344
Investment in joint ventures	**2,943**	2,201
Inventory	**-**	43
Partnership income deferral	**363**	434
Other	**718**	586
Total deferred tax liabilities	**25,183**	23,608
Deferred Tax Assets		
Benefit plan accruals	**2,063**	1,691
Asset retirement obligations and accrued environmental costs	**4,254**	3,971
Inventory	**43**	-
Deferred state income tax	**299**	257
Other financial accruals and deferrals	**618**	394
Loss and credit carryforwards	**1,608**	1,344
Other	**692**	717
Total deferred tax assets	**9,577**	8,374
Less valuation allowance	**(1,487)**	(1,400)
Net deferred tax assets	**8,090**	6,974

Net deferred tax liabilities	**$ 17,093**	16,634

Current assets, long-term assets, current liabilities and long-term liabilities included deferred taxes of $788 million, $183 million, $9 million and $18,055 million, respectively, at December 31, 2011, and $562 million, $160 million, $21 million and $17,335 million, respectively, at December 31, 2010.

We have loss and credit carryovers in multiple taxing jurisdictions. These attributes generally expire between 2012 and 2031 with some carryovers having indefinite carryforward periods.

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Valuation allowances have been established to reduce deferred tax assets to an amount that will, more likely than not, be realized. During 2011, valuation allowances increased a total of $87 million. This reflects increases of $174 million primarily related to U.S. foreign tax credit and foreign loss carryforwards, partially offset by decreases of $87 million, primarily related to utilization of U.S. foreign tax credit and state 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.

At December 31, 2011 and 2010, income considered to be permanently reinvested in certain foreign subsidiaries and foreign corporate joint ventures totaled approximately $4,227 million and $4,134 million, respectively. Deferred income taxes have not been provided on this income, as we do not plan to initiate any action that would require the payment of income taxes. It is not practicable to estimate the amount of additional tax that might be payable on this foreign income if distributed.

The following table shows a reconciliation of the beginning and ending unrecognized tax benefits for 2011, 2010 and 2009:

	Millions of Dollars		
	2011	2010	2009
Balance at January 1	**$ 1,125**	1,208	1,068
Additions based on tax positions related to the current year	**46**	63	18
Additions for tax positions of prior years	**145**	344	177
Reductions for tax positions of prior years	**(35)**	(199)	(33)
Settlements	**(206)**	(215)	(19)
Lapse of statute	**(4)**	(76)	(3)
Balance at December 31	**$ 1,071**	1,125	1,208

Included in the balance of unrecognized tax benefits for 2011, 2010 and 2009 were $815 million, $914 million and $931 million, respectively, which, if recognized, would affect our effective tax rate.

At December 31, 2011, 2010 and 2009, accrued liabilities for interest and penalties totaled $141 million, $171 million and $166 million, respectively, net of accrued income taxes. Interest and penalties resulted in a charge to earnings in 2011 of $10 million, a benefit to earnings in 2010 of $2 million, and a charge to earnings in 2009 of $18 million.

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 (2008), Canada (2005), United States (2006) and Norway (2010). 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.

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The amounts of U.S. and foreign income 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		
	2011	2010	2009	**2011**	2010	2009
Income before income taxes						
United States	$ **11,217**	6,214	2,456	**48.8%**	31.5	25.6
Foreign	**11,784**	13,536	7,126	**51.2**	68.5	74.4
	$ **23,001**	19,750	9,582	**100.0%**	100.0	100.0
Federal statutory income tax	$ **8,050**	6,912	3,354	**35.0%**	35.0	35.0
Capital loss utilization	**(563)**	-	-	**(2.5)**	-	-
Foreign taxes in excess of federal statutory rate	**2,736**	1,308	1,716	**11.9**	6.6	17.9
Federal manufacturing deduction	**(122)**	(82)	(19)	**(0.5)**	(0.4)	(0.2)
State income tax	**354**	206	81	**1.5**	1.0	0.8
Other	**44**	(11)	(42)	**0.2**	-	(0.4)
	$ **10,499**	8,333	5,090	**45.6%**	42.2	53.1

During 2011, we recognized a significant tax capital loss on disposition of the legal entity which ultimately holds the Wilhelmshaven Refinery assets. A large portion of the tax benefit of this loss was realized in 2011 because of other capital gains that occurred.

The change in the effective tax rate from 2010 to 2011was primarily due to the effect of asset dispositions occurring in 2010, partially offset by asset impairments occurring in 2010.

In the United Kingdom, legislation was enacted on July 19, 2011, which increased the supplementary corporate tax rate applicable to U.K. Upstream activity from 20 to 32 percent, retroactively effective from March 24, 2011. This resulted in the overall U.K. corporate rate increasing from 50 percent to 62 percent. The enactment resulted in increased income tax expense of $316 million in 2011. This is comprised of $106 million due to remeasurement of U.K. deferred tax liabilities, and $210 million to reflect the new rate from March 24, 2011, through the end of the year. Statutory tax rate changes did not have a significant impact on our income tax expense in 2010 or 2009.

Note 21 Accumulated Other Comprehensive Income

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

	Millions of Dollars				
	Defined Benefit Plans	Net Unrealized Gain on Securities	Foreign Currency Translation	Hedging	Accumulated Other Comprehensive Income (Loss)

December 31, 2008	$	(1,434)	-	(431)	(10)	(1,875)
Other comprehensive income (loss)		(70)	-	5,007	3	4,940
December 31, 2009		(1,504)	-	4,576	(7)	3,065
Other comprehensive income		146	158	1,404	-	1,708
December 31, 2010		(1,358)	158	5,980	(7)	4,773
Other comprehensive income (loss)		**(613)**	**(158)**	**(917)**	**1**	**(1,687)**
December 31, 2011	**$**	**(1,971)**	**-**	**5,063**	**(6)**	**3,086**

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Note 22 Cash Flow Information

		Millions of Dollars		
		2011	2010	2009
Noncash Investing and Financing Activities				
Increase in PP&E related to an increase in asset retirement obligations	$	**182**	808	974
Cash Payments				
Interest	$	**932**	1,210	998
Income taxes		**10,561**	8,474	6,641
Net Sales (Purchases) of Short-Term Investments				
Short-term investments purchased	$	**(6,744)**	(982)	-
Short-term investments sold		**7,144**	-	-
	$	**400**	(982)	-

Note 23 Other Financial Information

		Millions of Dollars Except Per Share Amounts		
		2011	2010	2009
Interest and Debt Expense				
Incurred				
Debt	$	**1,242**	1,414	1,485
Other		**218**	244	291
		1,460	1,658	1,776
Capitalized		**(488)**	(471)	(487)
Expensed	$	**972**	1,187	1,289
Other Income				
Interest income	$	**216**	187	227
Other, net		**113**	91	131
	$	**329**	278	358
Research and Development Expenditures expensed	$	**267**	230	190
Advertising Expenses	$	**92**	66	60

Shipping and Handling Costs*	**$**	**1,382**	1,366	1,185
**Amounts included in production and operating expenses.*				
Cash Dividends paid per common share	**$**	**2.64**	2.15	1.91
Foreign Currency Transaction (Gains) Losses after-tax				
E&P	**$**	**(17)**	(60)	111
Midstream		**-**	-	-
R&M		**(23)**	60	(36)
LUKOIL Investment		**(2)**	15	(20)
Chemicals		**-**	-	-
Emerging Businesses		**-**	1	(2)
Corporate and Other		**(20)**	15	(97)
	$	**(62)**	31	(44)

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Note 24 Related Party Transactions

Significant transactions with related parties were:

		Millions of Dollars		
		2011	2010	2009
Operating revenues and other income (a)	$	**8,353**	7,333	7,200
Gain on dispositions (b)		**156**	1,149	-
Purchases (c)		**20,696**	15,819	12,779
Operating expenses and selling, general and administrative expenses (d)		**392**	344	322
Net interest expense (e)		**71**	73	74

(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 CPChem, gas oil and hydrogen feedstocks were sold to Excel Paralubes and refined products were sold primarily to CFJ Properties and LUKOIL. Beginning in the third quarter of 2010, CFJ was no longer considered a related party due to the sale of our interest. Natural gas, crude oil, blendstock and other intermediate products were sold to WRB. In addition, we charged several of our affiliates, including CPChem and MSLP, for the use of common facilities, such as steam generators, waste and water treaters and warehouse facilities.

(b) In 2011, we sold the Seaway Products Pipeline to DCP Midstream for cash proceeds of $400 million, resulting in a before-tax gain of $156 million. During 2010, we sold a portion of our LUKOIL shares under a stock purchase and option agreement with a wholly owned subsidiary of LUKOIL, resulting in a before-tax gain of $1,149 million.

(c) 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 and refined products from MRC. We also paid fees to various pipeline equity companies for transporting finished refined products and natural gas, 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.

(d) We paid processing fees to various affiliates. Additionally, we paid transportation fees to pipeline equity companies.

(e) We paid and/or received interest to/from various affiliates, including FCCL. See Note 6 Investments, Loans and Long-Term Receivables, for additional information on loans to affiliated companies.

Beginning in the fourth quarter of 2010, transactions with LUKOIL and its subsidiaries were no longer considered related party transactions. See Note 6 Investments, Loans and Long-Term Receivables, for additional information.

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Note 25 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, bitumen, natural gas, LNG and natural gas liquids on a worldwide basis. At December 31, 2011, our E&P operations were producing in the United States, Norway, the United Kingdom, Canada, Australia, offshore Timor-Leste in the Timor Sea, Indonesia, China, Vietnam, Libya, Nigeria, Algeria, Qatar 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.

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, 2011, we owned or had an interest in 12 refineries in the United States, one in the United Kingdom, one in Ireland, one 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 prior investment in the ordinary shares of OAO LUKOIL, an international, integrated oil and gas company headquartered in Russia. We completed the divestiture of our entire interest in LUKOIL in the first quarter of 2011.

5) **Chemicals** This segment manufactures and markets petrochemicals and plastics on a worldwide basis. The Chemicals segment consists of our 50 percent equity investment in CPChem.

6) **Emerging Businesses** This segment 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, refining, alternative energy, biofuels and the environment.

Corporate and Other includes general corporate overhead, most interest expense and various other corporate activities. Corporate assets include all cash and cash equivalents and short-term investments.

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

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Analysis of Results by Operating Segment

		Millions of Dollars	
	2011	2010	2009
Sales and Other Operating Revenues			
E&P			
United States	$ **32,300**	28,934	24,287
International	**32,966**	27,992	24,222
Intersegment eliminations U.S.	**(7,639)**	(5,653)	(4,649)
Intersegment eliminations international	**(8,174)**	(7,748)	(6,763)
E&P	**49,453**	43,525	37,097
Midstream			
Total sales	**9,228**	7,714	5,199
Intersegment eliminations	**(499)**	(407)	(307)
Midstream	**8,729**	7,307	4,892
R&M			
United States	**127,204**	94,564	73,871
International	**60,373**	44,721	34,025
Intersegment eliminations U.S.	**(1,010)**	(763)	(613)
Intersegment eliminations international	**(65)**	(101)	(50)
R&M	**186,502**	138,421	107,233
LUKOIL Investment	**-**	-	-
Chemicals	**11**	11	11
Emerging Businesses			
Total sales	**822**	746	593
Intersegment eliminations	**(727)**	(595)	(507)
Emerging Businesses	**95**	151	86
Corporate and Other	**23**	26	22
Consolidated sales and other operating revenues	$ **244,813**	189,441	149,341
Depreciation, Depletion, Amortization and Impairments			
E&P			
United States	$ **2,800**	2,909	3,346
International	**4,429**	5,268	5,459
Total E&P	**7,229**	8,177	8,805
Midstream	**6**	6	6

R&M			
United States	**1,180**	711	707
International	**149**	1,789	215
Total R&M	**1,329**	2,500	922
LUKOIL Investment	**-**	-	-
Chemicals	**-**	-	-
Emerging Businesses	**54**	78	21
Corporate and Other	**108**	79	76
Consolidated depreciation, depletion, amortization and impairments	**$ 8,726**	10,840	9,830

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	Millions of Dollars		
	2011	2010	2009
Equity in Earnings of Affiliates			
E&P			
United States	$ **(53)**	39	(2)
International	**1,214**	(14)	233
Total E&P	**1,161**	25	231
Midstream	**563**	411	342
R&M			
United States	**1,283**	607	428
International	**95**	113	13
Total R&M	**1,378**	720	441
LUKOIL Investment	**-**	1,295	1,219
Chemicals	**975**	684	298
Emerging Businesses	**-**	(2)	-
Corporate and Other	**-**	-	-
Consolidated equity in earnings of affiliates	$ **4,077**	3,133	2,531
Income Taxes			
E&P			
United States	$ **1,901**	1,570	786
International	**6,929**	6,124	4,325
Total E&P	**8,830**	7,694	5,111
Midstream	**236**	158	171
R&M			
United States	**1,477**	645	32
International	**(42)**	(414)	9
Total R&M	**1,435**	231	41
LUKOIL Investment	**123**	514	12
Chemicals	**225**	182	47
Emerging Businesses	**(49)**	(54)	(16)
Corporate and Other	**(301)**	(392)	(276)
Consolidated income taxes	$ **10,499**	8,333	5,090

Net Income Attributable to ConocoPhillips

E&P			
United States	$ **3,254**	2,768	1,503
International	**4,988**	6,430	2,101
Total E&P	**8,242**	9,198	3,604
Midstream	**458**	306	313
R&M			
United States	**3,595**	1,022	(192)
International	**156**	(830)	229
Total R&M	**3,751**	192	37
LUKOIL Investment	**239**	2,503	1,219
Chemicals	**745**	498	248
Emerging Businesses	**(26)**	(59)	3
Corporate and Other	**(973)**	(1,280)	(1,010)
Consolidated net income attributable to ConocoPhillips	$ **12,436**	11,358	4,414

		Millions of Dollars		
		2011	2010	2009
Investments In and Advances To Affiliates				
E&P				
United States	**$**	**1,822**	1,989	1,978
International		**21,192**	21,049	19,646
Total E&P		**23,014**	23,038	21,624
Midstream		**1,146**	1,240	1,199
R&M				
United States		**4,090**	4,059	3,982
International		**1,326**	1,304	1,142
Total R&M		**5,416**	5,363	5,124
LUKOIL Investment		**-**	-	6,411
Chemicals		**2,998**	2,518	2,446
Emerging Businesses		**86**	76	77
Corporate and Other		**-**	-	-
Consolidated investments in and advances to affiliates(1)	**$**	**32,660**	32,235	36,881
(1) Includes amounts classified as held for sale:	*$*	**-**	-	*249*
Total Assets				
E&P				
United States	**$**	**37,150**	35,607	36,122
International		**64,752**	63,086	64,831
Total E&P		**101,902**	98,693	100,953
Midstream		**2,338**	2,506	2,054
R&M				
United States		**24,976**	26,028	24,963
International		**8,061**	8,463	8,446
Goodwill		**3,332**	3,633	3,638
Total R&M		**36,369**	38,124	37,047
LUKOIL Investment		**-**	1,129	6,416
Chemicals		**2,999**	2,732	2,451
Emerging Businesses		**974**	964	1,069
Corporate and Other		**8,648**	12,166	2,148
Consolidated total assets	**$**	**153,230**	156,314	152,138

Capital Expenditures and Investments			
E&P			
United States	$ **4,655**	2,585	3,474
International	**7,350**	5,908	5,425
Total E&P	**12,005**	8,493	8,899
Midstream	**17**	3	5
R&M			
United States	**768**	790	1,299
International	**226**	266	427
Total R&M	**994**	1,056	1,726
LUKOIL Investment	**-**	-	-
Chemicals	**-**	-	-
Emerging Businesses	**30**	27	97
Corporate and Other	**220**	182	134
Consolidated capital expenditures and investments	$ **13,266**	9,761	10,861

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		Millions of Dollars	
	2011	2010	2009
Interest Income and Expense			
Interest income			
Corporate	$ **108**	64	89
E&P	**75**	81	91
R&M	**33**	42	47
Interest and debt expense			
Corporate	$ **851**	1,047	1,133
E&P	**121**	140	156

Geographic Information

	$159,129	**$159,129**	**$159,129**	**$159,129**	**$159,129**	**$159,129**	**$159,129**
				Millions of Dollars			
	Sales and Other Operating Revenues*				Long-Lived Assets**		
	2011	2010	2009		**2011**	2010	2009
United States	$ **159,129**	124,173	97,674		**55,198**	53,706	53,761
Australia***	**3,458**	2,789	2,229		**12,572**	12,461	10,729
Canada	**7,076**	4,784	3,617		**20,083**	20,439	22,451
Norway	**2,209**	2,248	1,749		**5,918**	5,664	5,797
Russia	**-**	-	-		**341**	815	8,383
United Kingdom	**36,252**	26,693	20,671		**5,168**	4,885	5,778
Other foreign countries	**36,689**	28,754	23,401		**17,560**	16,819	17,441
Worldwide consolidated	$ **244,813**	189,441	149,341		**116,840**	114,789	124,340

**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 related to the joint petroleum development area with shared ownership held by Australia and Timor-Leste.*

Note 26 Planned Separation of Downstream Businesses

On July 14, 2011, we announced approval by our Board of Directors to pursue the separation of our refining, marketing and transportation businesses into a stand-alone, publicly traded corporation via a tax-free distribution. The new downstream company, named Phillips 66, will be headquartered in Houston, Texas. In addition to the refining, marketing and transportation businesses, we expect Phillips 66 will also include most of our Midstream segment, our Chemicals segment, as well as our power generation and certain technology operations included in our Emerging Businesses segment, to create an integrated downstream company. The separation is to be accomplished by the pro rata distribution of one share of Phillips 66 stock for every two shares of ConocoPhillips stock held by ConocoPhillips shareholders on the record date for the share distribution.

In October 2011, we requested a private letter ruling from the U.S. Internal Revenue Service, which is expected to confirm the distribution will qualify as a tax-free reorganization for U.S. federal income tax purposes. In addition, we filed the initial Phillips 66 Form 10 registration statement with the U.S. Securities and Exchange Commission on November 14, 2011, and an amendment on January 3, 2012.

The separation is subject to market conditions, customary regulatory approvals, the receipt of an affirmative Internal Revenue Service private letter ruling and final Board approval, and is expected to be completed in the second quarter of 2012.

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Oil and Gas Operations (Unaudited)

In accordance with Financial Accounting Standards Board (FASB) Accounting Standards Codification Topic 932, Extractive Activities Oil and Gas, 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.

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, for periods prior to 2011, 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.

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 commodity prices; 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, 2011, approximately 10 percent of our total proved reserves were under PSCs, primarily in our Asia Pacific/Middle East geographic reporting area.

Our disclosures by geographic area include the United States, Canada, Europe (primarily Norway and the United Kingdom), Russia, Asia Pacific/Middle East, Africa and Other Areas. Other Areas primarily consists of the Caspian Region.

In the following disclosures, the synthetic oil classification included our past Syncrude mining operations, and the bitumen classification includes our Surmont operations and the FCCL Partnership. In June 2010, we sold our interest in the Syncrude Canada Ltd. joint venture; accordingly, as of December 31, 2010, we no longer held synthetic oil reserves.

On July 28, 2010, we announced our intention to sell our entire interest in LUKOIL over a period of time through the end of 2011. As a result of this sell down of our interest, at the end of the third quarter of 2010 we ceased using equity-method accounting for our investment in LUKOIL. Accordingly, the supplemental oil and gas disclosures reflect activity for LUKOIL through June 30, 2010, which, on a lag basis, results in three quarters of activity being included in the year 2010 (the fourth quarter of 2009 and the first two quarters of 2010). Since the proved reserves tables are not on a lag basis, they reflect activity for the first three quarters of 2010, at which point LUKOIL s reserves were removed from our reserve quantities.

Reserves Governance

The recording and reporting of proved reserves are governed by criteria established by regulations of the SEC and FASB. Proved reserves are those quantities of oil and gas, which, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be economically producible from a given date forward, from known reservoirs, and under existing economic conditions, operating methods, and government regulations prior to the time at which contracts providing the right to operate expire, unless evidence indicates that renewal is reasonably certain, regardless of whether deterministic or probabilistic methods are used for the estimation. The project to extract the hydrocarbons must have commenced or the operator must be reasonably certain that it will commence the project within a reasonable time. Proved reserves are further classified as either developed or undeveloped. Proved developed reserves are proved reserves that can be expected to be recovered through existing wells with existing equipment and operating methods or in which the cost of the required equipment is relatively minor compared to the cost of a new well, and through installed extraction equipment and infrastructure operational at the time of the reserves estimate if the extraction is by means not involving a well. Proved undeveloped reserves are proved reserves that are expected to be recovered from new wells on undrilled acreage, or from existing wells where a relatively major expenditure is required for recompletion.

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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 which is headed by the company s Manager of Reserves Compliance and Reporting. This team, composed of internal reservoir engineers, geologists and finance personnel, reviews the business units reserves for adherence to SEC guidelines and company policy through on-site visits and review of documentation. In addition to providing independent reviews, 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 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 reserves held by consolidated companies and our share of equity affiliates have been estimated by ConocoPhillips.

The technical person primarily responsible for overseeing the preparation of the company s reserve estimates is the Manager of Reserves Compliance and Reporting. This individual is a petroleum engineer with a bachelor s degree in petroleum engineering. He is an active member of the Society of Petroleum Engineers (SPE) with over 30 years of oil and gas industry experience, including drilling and production engineering assignments in several field locations. He is currently serving a three-year term on the Oil & Gas Reserves Committee of the SPE and has held positions of increasing responsibility in reservoir engineering, reserves reporting and compliance, and business management.

During 2011, our processes and controls used to assess over 90 percent of proved reserves as of December 31, 2011, were reviewed by DeGolyer and MacNaughton (D&M), a third-party petroleum engineering consulting firm. The purpose of their review was to assess whether the adequacy and effectiveness of our internal processes and controls used to determine estimates of proved reserves are in accordance with SEC regulations. In such review, ConocoPhillips technical staff presented D&M with an overview of the reserves data, as well as the methods and assumptions used in estimating reserves. The data presented included pertinent seismic information, geologic maps, well logs, production tests, material balance calculations, reservoir simulation models, well performance data, operating procedures and relevant economic criteria. Management s intent in retaining D&M to review its processes and controls was to provide objective third-party input on these processes and controls. D&M s opinion was that the general processes and controls employed by ConocoPhillips in estimating its December 31, 2011, proved reserves for the properties reviewed are in accordance with the SEC reserves definitions. D&M s report is included as Exhibit 99 of this Annual Report on Form 10-K.

Engineering estimates of the quantities of proved reserves 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.

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Proved Reserves

Years Ended December 31	Crude Oil and Natural Gas Liquids Millions of Barrels									
	Alaska	Lower 48	Total U.S.	Canada	Europe	Asia Pacific/ Russia	Middle East	Africa	Other Areas	Total
Developed and Undeveloped										
Consolidated operations										
End of 2008	1,202	726	1,928	93	552	-	364	282	121	3,340
Revisions	84	1	85	-	29	-	(12)	10	(8)	104
Improved recovery	13	2	15	-	-	-	2	-	-	17
Purchases	-	-	-	-	-	-	-	-	-	-
Extensions and discoveries	14	17	31	3	7	-	26	3	-	70
Production	(93)	(60)	(153)	(15)	(87)	-	(48)	(28)	-	(331)
Sales	-	(1)	(1)	-	-	-	-	-	(5)	(6)
End of 2009	1,220	685	1,905	81	501	-	332	267	108	3,194
Revisions	81	8	89	15	28	-	7	21	-	160
Improved recovery	51	2	53	-	-	-	5	-	-	58
Purchases	-	1	1	-	-	-	-	-	-	1
Extensions and discoveries	17	30	47	4	18	-	7	10	-	86
Production	(84)	(55)	(139)	(14)	(78)	-	(51)	(28)	-	(310)
Sales	-	(22)	(22)	(6)	-	-	-	-	-	(28)
End of 2010	1,285	649	1,934	80	469	-	300	270	108	3,161
Revisions	70	45	115	10	(3)	-	(7)	5	-	120
Improved recovery	14	3	17	1	51	-	13	-	-	82
Purchases	-	1	1	-	-	-	-	-	-	1
Extensions and discoveries	21	68	89	4	102	-	8	-	-	203
Production	(79)	(60)	(139)	(13)	(64)	-	(41)	(14)	-	(271)
Sales	-	(8)	(8)	(1)	-	-	-	-	-	(9)
End of 2011	1,311	698	2,009	81	555	-	273	261	108	3,287
Equity affiliates										
End of 2008	-	-	-	-	-	1,568	109	-	-	1,677
Revisions	-	-	-	-	-	33	(3)	-	-	30
Improved recovery	-	-	-	-	-	54	-	-	-	54
Purchases	-	-	-	-	-	21	-	-	-	21
Extensions and discoveries	-	-	-	-	-	94	-	-	-	94
Production	-	-	-	-	-	(166)	-	-	-	(166)
Sales	-	-	-	-	-	-	-	-	-	-
End of 2009	-	-	-	-	-	1,604	106	-	-	1,710
Revisions	-	-	-	-	-	6	51	-	-	57
Improved recovery	-	-	-	-	-	-	-	-	-	-
Purchases	-	-	-	-	-	-	-	-	-	-
Extensions and discoveries	-	-	-	-	-	-	-	-	-	-
Production	-	-	-	-	-	(114)	(1)	-	-	(115)
Sales	-	-	-	-	-	(1,421)	-	-	-	(1,421)

End of 2010	-	-	-	-	-	75	156	-	-	231
Revisions	-	-	-	-	-	(37)	-	-	-	(37)
Improved recovery	-	-	-	-	-	-	-	-	-	-
Purchases	-	-	-	-	-	-	-	-	-	-
Extensions and discoveries	-	-	-	-	-	-	-	-	-	-
Production	-	-	-	-	-	(11)	(8)	-	-	(19)
Sales	-	-	-	-	-	-	-	-	-	-
End of 2011	-	-	-	-	-	27	148	-	-	175
Total company										
End of 2008	1,202	726	1,928	93	552	1,568	473	282	121	5,017
End of 2009	1,220	685	1,905	81	501	1,604	438	267	108	4,904
End of 2010	1,285	649	1,934	80	469	75	456	270	108	3,392
End of 2011	1,311	698	2,009	81	555	27	421	261	108	3,462

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Years Ended December 31	Crude Oil and Natural Gas Liquids Millions of Barrels									
	Alaska	Lower 48	Total U.S.	Canada	Europe	Asia Pacific/ Russia	Middle East	Africa	Other Areas	Total
Developed										
Consolidated operations										
End of 2008	1,104	572	1,676	85	342	-	217	264	6	2,590
End of 2009	1,130	558	1,688	77	312	-	221	246	-	2,544
End of 2010	1,155	534	1,689	75	290	-	218	251	-	2,523
End of 2011	1,182	564	1,746	74	317	-	187	248	-	2,572
Equity affiliates										
End of 2008	-	-	-	-	-	1,228	-	-	-	1,228
End of 2009	-	-	-	-	-	1,213	-	-	-	1,213
End of 2010	-	-	-	-	-	73	156	-	-	229
End of 2011	-	-	-	-	-	27	148	-	-	175
Undeveloped										
Consolidated operations										
End of 2008	98	154	252	8	210	-	147	18	115	750
End of 2009	90	127	217	4	189	-	111	21	108	650
End of 2010	130	115	245	5	179	-	82	19	108	638
End of 2011	129	134	263	7	238	-	86	13	108	715
Equity affiliates										
End of 2008	-	-	-	-	-	340	109	-	-	449
End of 2009	-	-	-	-	-	391	106	-	-	497
End of 2010	-	-	-	-	-	2	-	-	-	2
End of 2011	-	-	-	-	-	-	-	-	-	-

Notable changes in proved crude oil and natural gas liquids reserves in the three years ended December 31, 2011, included:

Revisions: In 2009, revisions in Alaska were primarily due to higher prices in 2009, versus 2008.

Extensions and discoveries: In 2011, extensions and discoveries in Europe were primarily due to the sanctioning of the Ekofisk South and Clair Ridge development projects in the North Sea.

Sales: In 2010, for our equity affiliates in Russia, sales were primarily due to the disposition of our interest in LUKOIL.

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Years Ended December 31	Natural Gas Billions of Cubic Feet									
	Alaska	Lower 48	Total U.S.	Canada	Europe	Russia	Asia Pacific/ Middle East	Africa	Other Areas	Total
Developed and Undeveloped										
Consolidated operations										
End of 2008	2,488	8,432	10,920	2,614	2,303	-	3,237	998	88	20,160
Revisions	400	126	526	(23)	19	-	(94)	(2)	(32)	394
Improved recovery	3	-	3	-	-	-	-	-	-	3
Purchases	-	-	-	2	-	-	-	-	-	2
Extensions and discoveries	-	146	146	95	24	-	54	-	-	319
Production	(111)	(739)	(850)	(388)	(337)	-	(285)	(46)	-	(1,906)
Sales	-	(3)	(3)	(4)	-	-	-	-	-	(7)
End of 2009	2,780	7,962	10,742	2,296	2,009	-	2,912	950	56	18,965
Revisions	155	365	520	309	86	-	(39)	36	-	912
Improved recovery	24	1	25	-	-	-	-	-	-	25
Purchases	-	9	9	-	-	-	-	-	-	9
Extensions and discoveries	4	122	126	84	89	-	24	-	-	323
Production	(101)	(663)	(764)	(358)	(323)	-	(289)	(60)	-	(1,794)
Sales	-	(179)	(179)	(26)	-	-	-	-	-	(205)
End of 2010	2,862	7,617	10,479	2,305	1,861	-	2,608	926	56	18,235
Revisions	186	15	201	134	70	-	(8)	9	-	406
Improved recovery	1	5	6	-	53	-	-	-	-	59
Purchases	-	7	7	1	-	-	-	-	-	8
Extensions and discoveries	3	171	174	78	158	-	192	-	-	602
Production	(92)	(616)	(708)	(338)	(246)	-	(277)	(63)	-	(1,632)
Sales	-	(11)	(11)	(67)	-	-	-	-	-	(78)
End of 2011	2,960	7,188	10,148	2,113	1,896	-	2,515	872	56	17,600
Equity affiliates										
End of 2008	-	-	-	-	-	2,269	2,519	-	-	4,788
Revisions	-	-	-	-	-	436	(203)	-	-	233
Improved recovery	-	-	-	-	-	-	-	-	-	-
Purchases	-	-	-	-	-	25	-	-	-	25
Extensions and discoveries	-	-	-	-	-	89	294	-	-	383
Production	-	-	-	-	-	(114)	(33)	-	-	(147)
Sales	-	-	-	-	-	-	-	-	-	-
End of 2009	-	-	-	-	-	2,705	2,577	-	-	5,282
Revisions	-	-	-	-	-	19	683	-	-	702
Improved recovery	-	-	-	-	-	-	-	-	-	-
Purchases	-	-	-	-	-	-	-	-	-	-
Extensions and discoveries	-	-	-	-	-	-	269	-	-	269
Production	-	-	-	-	-	(91)	(65)	-	-	(156)
Sales	-	-	-	-	-	(2,616)	-	-	-	(2,616)
End of 2010	-	-	-	-	-	17	3,464	-	-	3,481
Revisions	-	-	-	-	-	(11)	(76)	-	-	(87)

Improved recovery	-	-	-	-	-	-	-	-	-	-
Purchases	-	-	-	-	-	-	-	-	-	-
Extensions and discoveries	-	-	-	-	-	-	259	-	-	259
Production	-	-	-	-	-	(2)	(184)	-	-	(186)
Sales	-	-	-	-	-	-	(151)	-	-	(151)
End of 2011	-	-	-	-	-	4	3,312	-	-	3,316
Total company										
End of 2008	2,488	8,432	10,920	2,614	2,303	2,269	5,756	998	88	24,948
End of 2009	2,780	7,962	10,742	2,296	2,009	2,705	5,489	950	56	24,247
End of 2010	2,862	7,617	10,479	2,305	1,861	17	6,072	926	56	21,716
End of 2011	2,960	7,188	10,148	2,113	1,896	4	5,827	872	56	20,916

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Years Ended December 31	Natural Gas Billions of Cubic Feet									
	Alaska	Lower 48	Total U.S.	Canada	Europe	Russia	Asia Pacific/ Middle East	Africa	Other Areas	Total
Developed										
Consolidated operations										
End of 2008	2,413	6,875	9,288	2,272	2,036	-	2,877	936	-	17,409
End of 2009	2,744	6,633	9,377	2,173	1,772	-	2,537	889	-	16,748
End of 2010	2,785	6,399	9,184	2,134	1,529	-	2,136	865	-	15,848
End of 2011	2,907	6,194	9,101	1,932	1,439	-	1,932	738	-	15,142
Equity affiliates										
End of 2008	-	-	-	-	-	1,458	361	-	-	1,819
End of 2009	-	-	-	-	-	1,506	307	-	-	1,813
End of 2010	-	-	-	-	-	17	3,114	-	-	3,131
End of 2011	-	-	-	-	-	4	2,943	-	-	2,947
Undeveloped										
Consolidated operations										
End of 2008	75	1,557	1,632	342	267	-	360	62	88	2,751
End of 2009	36	1,329	1,365	123	237	-	375	61	56	2,217
End of 2010	77	1,218	1,295	171	332	-	472	61	56	2,387
End of 2011	53	994	1,047	181	457	-	583	134	56	2,458
Equity affiliates										
End of 2008	-	-	-	-	-	811	2,158	-	-	2,969
End of 2009	-	-	-	-	-	1,199	2,270	-	-	3,469
End of 2010	-	-	-	-	-	-	350	-	-	350
End of 2011	-	-	-	-	-	-	369	-	-	369

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.

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, 2011, included:

Revisions: In 2010, revisions in Alaska, Lower 48 and Canada were primarily due to higher prices in 2010, versus 2009, as well as improved well performance. In 2009, revisions in Alaska were primarily due to higher prices in 2009, versus 2008. In 2009, for our equity affiliate operations in Asia Pacific/Middle East, revisions resulted from modified coalbed methane drilling plans in Australia. In Russia, revisions were attributable to positive performance in various LUKOIL fields.

Extensions and discoveries: In 2011, for our equity affiliate operations in Asia Pacific/Middle East, extensions and discoveries were primarily due to ongoing development drilling onshore Australia associated with the APLNG Project. In 2010, extensions and discoveries in Lower 48 and Canada were primarily due to continued drilling success in various fields. In 2009, for our equity affiliate operations in Asia Pacific/Middle East, extensions and discoveries primarily resulted from drilling success in Australia related to a coalbed methane project.

Sales: In 2010, for our equity affiliates in Russia, sales were primarily due to the disposition of our interest in LUKOIL.

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Years Ended	Other Products	
December 31	Millions of Barrels	
	Synthetic Oil	**Bitumen**
	Canada	Canada
Developed and Undeveloped		
Consolidated operations		
End of 2008	-	100
Revisions	256	152
Improved recovery	-	-
Purchases	-	-
Extensions and discoveries	-	167
Production	(8)	(2)
Sales	-	-
End of 2009	248	417
Revisions	-	42
Improved recovery	-	-
Purchases	-	-
Extensions and discoveries	-	-
Production	(4)	(4)
Sales	(244)	-
End of 2010	-	455
Revisions	-	(1)
Improved recovery	-	-
Purchases	-	-
Extensions and discoveries	-	79
Production	-	(3)
Sales	-	-
End of 2011	-	530
Equity affiliates		
End of 2008	-	700
Revisions	-	(87)
Improved recovery	-	-
Purchases	-	-
Extensions and discoveries	-	118
Production	-	(15)
Sales	-	-
End of 2009	-	716
Revisions	-	13
Improved recovery	-	-
Purchases	-	-
Extensions and discoveries	-	133
Production	-	(18)
Sales	-	-
End of 2010	-	844
Revisions	-	(101)

Improved recovery	-	-
Purchases	-	-
Extensions and discoveries	-	187
Production	-	(21)
Sales	-	-
End of 2011	-	909
Total company		
End of 2008	-	800
End of 2009	248	1,133
End of 2010	-	1,299
End of 2011	-	1,439

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Years Ended December 31	Other Products	
	Millions of Barrels	
	Synthetic Oil	**Bitumen**
	Canada	Canada
Developed		
Consolidated operations		
End of 2008	-	24
End of 2009	248	24
End of 2010	-	34
End of 2011	-	29
Equity affiliates		
End of 2008	-	105
End of 2009	-	116
End of 2010	-	142
End of 2011	-	131
Undeveloped		
Consolidated operations		
End of 2008	-	76
End of 2009	-	393
End of 2010	-	421
End of 2011	-	501
Equity affiliates		
End of 2008	-	595
End of 2009	-	600
End of 2010	-	702
End of 2011	-	778

Notable changes in proved synthetic oil and bitumen reserves in the three years ended December 31, 2011, included:

Revisions: In 2011, for our bitumen equity operations, revisions were primarily due to new subsurface interpretations, as well as the effects of higher prices on sliding scale royalty provisions. In 2009, for synthetic oil consolidated operations, revisions reflect our Syncrude Canada Ltd. operations. For our bitumen consolidated operations, revisions primarily were related to the sanction of the Surmont Phase II Project. For our bitumen equity affiliate operations, revisions were mainly the result of the effect of higher prices on sliding scale royalty provisions.

Extensions and discoveries: In 2011, for our consolidated operations, extensions and discoveries were related to continued development of Surmont. For our equity affiliate operations, extensions and discoveries were related to the sanctioning of new projects in FCCL. In 2009, for our bitumen consolidated operations, extensions and discoveries were related to the sanction of the Surmont Phase II Project. In 2010 and 2009, for our equity affiliate operations, extensions and discoveries mainly reflect the continued development of FCCL.

Sales: In 2010, for synthetic oil consolidated operations, sales reflect the disposition of our interest in Syncrude.

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Years Ended December 31	Total Proved Reserves									
	Millions of Barrels of Oil Equivalent									
	Alaska	Lower 48	Total U.S.	Canada	Europe	Russia	Asia Pacific/ Middle East	Africa	Other Areas	Total
Developed and Undeveloped										
Consolidated operations										
End of 2008	1,617	2,131	3,748	629	936	-	904	448	135	6,800
Revisions	151	22	173	404	32	-	(28)	10	(13)	578
Improved recovery	14	2	16	-	-	-	2	-	-	18
Purchases	-	-	-	-	-	-	-	-	-	-
Extensions and discoveries	14	41	55	186	11	-	35	3	-	290
Production	(112)	(183)	(295)	(89)	(143)	-	(96)	(36)	-	(659)
Sales	-	(1)	(1)	(1)	-	-	-	-	(5)	(7)
End of 2009	1,684	2,012	3,696	1,129	836	-	817	425	117	7,020
Revisions	107	68	175	109	42	-	1	27	-	354
Improved recovery	55	2	57	-	-	-	5	-	-	62
Purchases	-	2	2	-	-	-	-	-	-	2
Extensions and discoveries	17	51	68	18	33	-	11	10	-	140
Production	(101)	(165)	(266)	(82)	(132)	-	(99)	(38)	-	(617)
Sales	-	(52)	(52)	(254)	-	-	-	-	-	(306)
End of 2010	1,762	1,918	3,680	920	779	-	735	424	117	6,655
Revisions	101	48	149	31	8	-	(9)	7	-	186
Improved recovery	14	4	18	1	60	-	13	-	-	92
Purchases	-	2	2	-	-	-	-	-	-	2
Extensions and discoveries	21	97	118	97	128	-	40	-	-	383
Production	(94)	(163)	(257)	(73)	(105)	-	(86)	(25)	-	(546)
Sales	-	(10)	(10)	(12)	-	-	-	-	-	(22)
End of 2011	1,804	1,896	3,700	964	870	-	693	406	117	6,750
Equity affiliates										
End of 2008	-	-	-	700	-	1,946	529	-	-	3,175
Revisions	-	-	-	(87)	-	106	(37)	-	-	(18)
Improved recovery	-	-	-	-	-	54	-	-	-	54
Purchases	-	-	-	-	-	25	-	-	-	25
Extensions and discoveries	-	-	-	118	-	109	49	-	-	276
Production	-	-	-	(15)	-	(185)	(6)	-	-	(206)
Sales	-	-	-	-	-	-	-	-	-	-
End of 2009	-	-	-	716	-	2,055	535	-	-	3,306
Revisions	-	-	-	13	-	9	165	-	-	187
Improved recovery	-	-	-	-	-	-	-	-	-	-
Purchases	-	-	-	-	-	-	-	-	-	-
Extensions and discoveries	-	-	-	133	-	-	45	-	-	178
Production	-	-	-	(18)	-	(129)	(12)	-	-	(159)
Sales	-	-	-	-	-	(1,857)*	-	-	-	(1,857)

End of 2010	-	-	-	844	-	78	733	-	-	1,655
Revisions	-	-	-	(101)	-	(39)	(12)	-	-	(152)
Improved recovery	-	-	-	-	-	-	-	-	-	-
Purchases	-	-	-	-	-	-	-	-	-	-
Extensions and discoveries	-	-	-	187	-	-	43	-	-	230
Production	-	-	-	(21)	-	(11)	(39)	-	-	(71)
Sales	-	-	-	-	-	-	(25)	-	-	(25)
End of 2011	-	-	-	909	-	28	700	-	-	1,637
Total company										
End of 2008	1,617	2,131	3,748	1,329	936	1,946	1,433	448	135	9,975
End of 2009	1,684	2,012	3,696	1,845	836	2,055	1,352	425	117	10,326
End of 2010	1,762	1,918	3,680	1,764	779	78	1,468	424	117	8,310
End of 2011	1,804	1,896	3,700	1,873	870	28	1,393	406	117	8,387

**Includes 594 million barrels of oil equivalent due to the cessation of equity accounting.*

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Years Ended December 31	Alaska	Lower 48	Total U.S.	Canada	Europe	Russia	Asia Pacific/ Middle East	Africa	Other Areas	Total
	Total Proved Reserves									
	Millions of Barrels of Oil Equivalent									
Developed										
Consolidated operations										
End of 2008	1,506	1,718	3,224	488	681	-	697	420	6	5,516
End of 2009	1,588	1,663	3,251	711	608	-	644	394	-	5,608
End of 2010	1,619	1,601	3,220	465	545	-	574	396	-	5,200
End of 2011	1,666	1,597	3,263	425	556	-	510	371	-	5,125
Equity affiliates										
End of 2008	-	-	-	105	-	1,471	60	-	-	1,636
End of 2009	-	-	-	116	-	1,464	51	-	-	1,631
End of 2010	-	-	-	142	-	76	675	-	-	893
End of 2011	-	-	-	131	-	28	638	-	-	797
Undeveloped										
Consolidated operations										
End of 2008	111	413	524	141	255	-	207	28	129	1,284
End of 2009	96	349	445	418	228	-	173	31	117	1,412
End of 2010	143	317	460	455	234	-	161	28	117	1,455
End of 2011	138	299	437	539	314	-	183	35	117	1,625
Equity affiliates										
End of 2008	-	-	-	595	-	475	469	-	-	1,539
End of 2009	-	-	-	600	-	591	484	-	-	1,675
End of 2010	-	-	-	702	-	2	58	-	-	762
End of 2011	-	-	-	778	-	-	62	-	-	840

Natural gas reserves are converted to barrels of oil equivalent (BOE) based on a 6:1 ratio: six thousand cubic feet of natural gas converts to one BOE.

Proved Undeveloped Reserves

We had 2,465 million BOE of proved undeveloped reserves at year-end 2011, compared with 2,217 million BOE at year-end 2010. We converted 210 million BOE of undeveloped reserves to developed during 2011 as we achieved startup of major development projects. In addition, we added 458 million BOE of undeveloped reserves in 2011 mainly through exploratory success and revisions. As a result, at December 31, 2011, our proved undeveloped reserves represented 29 percent of total proved reserves, compared with 27 percent at December 31, 2010. Costs incurred for the year ended December 31, 2011, relating to the development of proved undeveloped reserves were $4.5 billion.

Approximately 70 percent of our proved undeveloped reserves at year-end 2011 were associated with eight major development areas. Seven of the major development areas are currently producing and are expected to have proved undeveloped reserves convert to developed over time as development activities continue and/or production facilities are expanded or upgraded, and include:

- FCCL oil sands Foster Creek and Christina Lake in Canada.
- The Surmont oil sands project in Canada.
- The Ekofisk Field in the North Sea.
- Certain fields in the Lower 48 and Alaska.

The remaining major project, the Kashagan Field in Kazakhstan, will have proved undeveloped reserves convert to developed as this project begins production.

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At the end of 2011, we did not have any material amounts of proved undeveloped reserves in individual fields or countries that have remained undeveloped for five years or more. However, our largest concentrations of proved undeveloped reserves at year-end 2011 are located in the Athabasca oil sands in Canada, consisting of the FCCL and Surmont steam-assisted gravity drainage (SAGD) projects. The majority of our proved undeveloped reserves in this area were first recorded in 2006 and 2007, and we expect a material portion of these reserves will remain undeveloped for more than five years.

Our SAGD projects are large, multi-year projects with steady, long-term production at consistent levels. The associated reserves are expected to be developed over many years as additional well pairs are drilled across the extensive resource base to maintain throughput at the central processing facilities.

Results of Operations

The company s results of operations from oil and gas activities for the years 2011, 2010 and 2009 are shown in the following tables. Additional information about selected line items within the results of operations tables is shown below:

Other revenues include gains and losses from asset sales, certain amounts resulting from the purchase and sale of hydrocarbons, and other miscellaneous income.

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

Depreciation of support equipment is reclassified as applicable.

Transportation costs include costs to transport our produced hydrocarbons 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.

Other earnings include non-oil and gas activities within the E&P segment, such as pipeline and marine operations, liquefied natural gas operations, and crude oil and gas marketing activities.

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Year Ended December 31, 2011	Millions of Dollars									
	Alaska	Lower 48	Total U.S.	Canada	Europe	Russia	Asia Pacific/ Middle East	Africa	Other Areas	Total
Consolidated operations										
Sales	$ 4,319	3,513	7,832	2,123	5,233	-	5,901	1,486	-	22,575
Transfers	3,869	3,283	7,152	176	3,854	-	932	54	-	12,168
Other revenues	(46)	303	257	138	(16)	-	(264)	30	16	161
Total revenues	8,142	7,099	15,241	2,437	9,071	-	6,569	1,570	16	34,904
Production costs excluding taxes	1,023	1,286	2,309	781	956	-	742	266	-	5,054
Taxes other than income taxes	2,721	520	3,241	65	4	1	543	23	-	3,877
Exploration expenses	36	368	404	177	201	-	192	51	54	1,079
Depreciation, depletion and amortization	468	2,113	2,581	1,504	1,407	1	940	188	-	6,621
Impairments	2	71	73	253	(38)	-	-	-	-	288
Transportation costs	609	432	1,041	128	273	-	120	27	-	1,589
Other related expenses	49	60	109	55	63	20	87	(7)	56	383
Accretion	59	58	117	50	203	-	23	2	1	396
	3,175	2,191	5,366	(576)	6,002	(22)	3,922	1,020	(95)	15,617
Provision for income taxes	1,167	755	1,922	(194)	4,355	3	1,844	722	(23)	8,629
Results of operations for producing activities	2,008	1,436	3,444	(382)	1,647	(25)	2,078	298	(72)	6,988
Other earnings	(25)	(165)	(190)	(32)	248	11	191	11	7	246
Net income (loss) attributable to ConocoPhillips	$ 1,983	1,271	3,254	(414)	1,895	(14)	2,269	309	(65)	7,234
Equity affiliates										
Sales	$ -	-	-	1,295	-	1,107	956	-	-	3,358
Transfers	-	-	-	-	-	-	365	-	-	365
Other revenues	-	-	-	6	-	-	6	-	-	12
Total revenues	-	-	-	1,301	-	1,107	1,327	-	-	3,735
Production costs excluding taxes	-	-	-	367	-	72	108	-	-	547
Taxes other than income taxes	-	-	-	5	-	750	187	-	-	942
Exploration expenses	-	-	-	36	-	1	2	-	-	39
Depreciation, depletion and amortization	-	-	-	209	-	52	128	-	-	389
Impairments	-	-	-	-	-	395	-	-	-	395
Transportation costs	-	-	-	-	-	139	133	-	-	272
Other related expenses	-	-	-	3	-	-	41	-	-	44
Accretion	-	-	-	4	-	1	3	-	-	8
	-	-	-	677	-	(303)	725	-	-	1,099
Provision for income taxes	-	-	-	159	-	18	32	-	-	209

Results of operations for producing activities		-	-	-	518	-	(321)	693	-	-	890
Other earnings		-	-	-	-	-	238	119	-	-	357
Net income (loss) attributable to ConocoPhillips	$	-	-	-	518	-	(83)	812	-	-	1,247

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Year Ended December 31, 2010	Millions of Dollars									
	Alaska	Lower 48	Total U.S.	Canada	Europe	Russia	Asia Pacific/ Middle East	Africa	Other Areas	Total
Consolidated operations										
Sales	$ 3,645	3,600	7,245	2,379	5,967	-	4,958	1,743	-	22,292
Transfers	2,693	2,389	5,082	246	2,278	-	770	450	-	8,826
Other revenues	-	559	559	3,216	142	-	55	172	18	4,162
Total revenues	6,338	6,548	12,886	5,841	8,387	-	5,783	2,365	18	35,280
Production costs excluding taxes	849	1,230	2,079	873	1,004	-	538	296	-	4,790
Taxes other than income taxes	1,570	498	2,068	74	6	1	355	18	1	2,523
Exploration expenses	37	292	329	295	146	2	260	29	101	1,162
Depreciation, depletion and amortization	529	2,231	2,760	1,666	1,972	2	1,206	202	-	7,808
Impairments	4	19	23	13	43	-	-	-	-	79
Transportation costs	528	424	952	134	281	-	119	23	-	1,509
Other related expenses	(38)	112	74	41	42	17	(48)	(10)	62	178
Accretion	58	55	113	50	192	-	24	-	4	383
	2,801	1,687	4,488	2,695	4,701	(22)	3,329	1,807	(150)	16,848
Provision for income taxes	1,014	555	1,569	108	3,066	(23)	1,361	1,458	(28)	7,511
Results of operations for producing activities	1,787	1,132	2,919	2,587	1,635	1	1,968	349	(122)	9,337
Other earnings	(52)	(99)	(151)	(72)	76	16	139	29	8	45
Net income (loss) attributable to ConocoPhillips	$ 1,735	1,033	2,768	2,515	1,711	17	2,107	378	(114)	9,382
Equity affiliates										
Sales	$ -	-	-	955	-	5,189	249	-	-	6,393
Transfers	-	-	-	-	-	1,876	-	-	-	1,876
Other revenues	-	-	-	7	-	1,219	10	-	-	1,236
Total revenues	-	-	-	962	-	8,284	259	-	-	9,505
Production costs excluding taxes	-	-	-	265	-	544	59	-	-	868
Taxes other than income taxes	-	-	-	4	-	3,463	42	-	-	3,509
Exploration expenses	-	-	-	-	-	61	(2)	-	-	59
Depreciation, depletion and amortization	-	-	-	190	-	568	55	-	-	813
Impairments	-	-	-	-	-	645	-	-	-	645
Transportation costs	-	-	-	-	-	784	25	-	-	809
Other related expenses	-	-	-	(3)	-	-	44	-	-	41
Accretion	-	-	-	2	-	7	2	-	-	11
	-	-	-	504	-	2,212	34	-	-	2,750
Provision for income taxes	-	-	-	128	-	647	(25)	-	-	750

Results of operations for producing activities		-	-	-	376	-	1,565	59	-	-	2,000
Other earnings		-	-	-	-	-	405	(86)	-	-	319
Net income (loss) attributable to ConocoPhillips	$	-	-	-	376	-	1,970	(27)	-	-	2,319

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Year Ended December 31, 2009	Millions of Dollars									
	Alaska	Lower 48	Total U.S.	Canada	Europe	Russia	Asia Pacific/ Middle East	Africa	Other Areas	Total
Consolidated operations										
Sales	$ 3,353	3,144	6,497	2,179	4,995	-	3,830	1,562	11	19,074
Transfers	2,261	1,937	4,198	345	2,305	-	500	257	-	7,605
Other revenues	30	54	84	168	(66)	-	10	136	54	386
Total revenues	5,644	5,135	10,779	2,692	7,234	-	4,340	1,955	65	27,065
Production costs excluding taxes	864	1,266	2,130	1,011	1,048	-	445	270	8	4,912
Taxes other than income taxes	1,135	422	1,557	75	3	1	165	17	7	1,825
Exploration expenses	74	426	500	201	156	4	212	32	75	1,180
Depreciation, depletion and amortization	611	2,615	3,226	1,689	2,016	2	910	201	11	8,055
Impairments	-	5	5	296	104	-	12	-	51	468
Transportation costs	548	392	940	135	267	-	111	24	5	1,482
Other related expenses	251	60	311	(3)	62	3	121	23	14	531
Accretion	49	55	104	41	191	-	19	3	3	361
	2,112	(106)	2,006	(753)	3,387	(10)	2,345	1,385	(109)	8,251
Provision for income taxes	716	(79)	637	(309)	2,280	(3)	1,093	1,186	(21)	4,863
Results of operations for producing activities	1,396	(27)	1,369	(444)	1,107	(7)	1,252	199	(88)	3,388
Other earnings	144	(10)	134	(91)	(59)	(5)	132	4	(1)	114
Net income (loss) attributable to ConocoPhillips	$ 1,540	(37)	1,503	(535)	1,048	(12)	1,384	203	(89)	3,502
Equity affiliates										
Sales	$ -	-	-	713	-	3,783	74	-	-	4,570
Transfers	-	-	-	-	-	1,946	-	-	-	1,946
Other revenues	-	-	-	(2)	-	-	1	-	-	(1)
Total revenues	-	-	-	711	-	5,729	75	-	-	6,515
Production costs excluding taxes	-	-	-	213	-	501	26	-	-	740
Taxes other than income taxes	-	-	-	3	-	2,270	4	-	-	2,277
Exploration expenses	-	-	-	-	-	37	2	-	-	39
Depreciation, depletion and amortization	-	-	-	133	-	455	21	-	-	609
Impairments	-	-	-	-	-	83	-	-	-	83
Transportation costs	-	-	-	-	-	703	3	-	-	706
Other related expenses	-	-	-	17	-	3	1	-	-	21
Accretion	-	-	-	1	-	6	1	-	-	8
	-	-	-	344	-	1,671	17	-	-	2,032
Provision for income taxes	-	-	-	89	-	326	9	-	-	424

Results of operations for producing activities		-	-	-	255	-	1,345	8	-	-	1,608
Other earnings		-	-	-	-	-	(201)	(86)	-	-	(287)
Net income (loss) attributable to ConocoPhillips	$	-	-	-	255	-	1,144	(78)	-	-	1,321

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Statistics

Net Production	**2011**	2010	2009
	Thousands of Barrels Daily		
Crude Oil and Natural Gas Liquids			
Consolidated operations			
Alaska	**215**	230	252
Lower 48	**168**	160	166
United States	**383**	390	418
Canada	**38**	38	40
Europe	**175**	211	241
Asia Pacific/Middle East	**111**	140	132
Africa	**40**	79	78
Other areas	**-**	-	4
Total consolidated operations	**747**	858	913
Equity affiliates			
Russia	**29**	336	443
Asia Pacific/Middle East	**23**	3	-
Total equity affiliates	**52**	339	443
Total company	**799**	1,197	1,356
Synthetic Oil			
Consolidated operations Canada	**-**	12	23
Bitumen			
Consolidated operations Canada	**10**	10	7
Equity affiliates Canada	**57**	49	43
Total company	**67**	59	50
	Millions of Cubic Feet Daily		
Natural Gas*			
Consolidated operations			
Alaska	**61**	82	94
Lower 48	**1,556**	1,695	1,927
United States	**1,617**	1,777	2,021
Canada	**928**	984	1,062
Europe	**626**	815	876

Asia Pacific/Middle East	**695**	712	713
Africa	**158**	149	121
Total consolidated operations	**4,024**	4,437	4,793
Equity affiliates			
Russia	**-**	254	295
Asia Pacific/Middle East	**492**	169	84
Total equity affiliates	**492**	423	379
Total company	**4,516**	4,860	5,172

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

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Average Sales Prices	00000000 **2011**	00000000 2010	00000000 2009
Crude Oil and Natural Gas Liquids Per Barrel			
Consolidated operations			
Alaska	$ **105.95**	78.61	59.23
Lower 48	**74.09**	57.69	44.12
United States	**91.77**	69.73	53.21
Canada	**66.07**	55.70	41.76
Europe	**108.58**	77.35	58.92
Asia Pacific/Middle East	**105.94**	75.50	57.59
Africa	**102.75**	76.80	60.83
Other areas	**-**	-	32.01
Total international	**102.68**	74.95	57.40
Total consolidated operations	**97.12**	72.63	55.47
Equity affiliates			
Russia	**101.62**	56.65	43.19
Asia Pacific/Middle East	**94.67**	83.82	-
Total equity affiliates	**98.60**	56.87	43.19
Synthetic Oil Per Barrel			
Consolidated operations Canada	$ **-**	77.56	62.01
Bitumen Per Barrel			
Consolidated operations Canada	$ **55.16**	51.10	39.67
Equity affiliates Canada	**63.93**	53.43	45.69
Natural Gas Per Thousand Cubic Feet			
Consolidated operations			
Alaska	$ **4.56**	4.62	5.33
Lower 48	**3.99**	4.25	3.42
United States	**4.01**	4.27	3.50
Canada	**3.46**	3.74	3.33
Europe	**9.26**	6.94	6.81
Asia Pacific/Middle East	**9.82**	7.39	6.00
Africa	**2.24**	1.81	1.56
Total international	**6.73**	5.60	5.06
Total consolidated operations	**5.64**	5.07	4.40
Equity affiliates			
Russia	**-**	1.18	1.16
Asia Pacific/Middle East	**2.89**	2.79	2.35
Total equity affiliates	**2.89**	1.82	1.43

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		2011	2010	2009
Average Production Costs Per Barrel of Oil Equivalent*				
Consolidated operations				
Alaska	$	**12.45**	9.55	8.84
Lower 48		**8.24**	7.62	7.12
United States		**9.70**	8.30	7.73
Canada		**10.56**	10.68	11.21
Europe		**9.38**	7.93	7.42
Asia Pacific/Middle East		**8.96**	5.70	4.86
Africa		**10.99**	7.81	7.54
Other areas		**-**	-	5.48
Total international		**9.70**	7.96	7.72
Total consolidated operations		**9.70**	8.10	7.73
Equity affiliates				
Canada		**17.64**	14.82	13.57
Russia		**6.80**	3.94	3.74
Asia Pacific/Middle East		**2.82**	5.19	5.09
Total equity affiliates		**7.85**	5.19	4.54
Average Production Costs Per Barrel Bitumen				
Consolidated operations Canada	$	**27.12**	19.45	30.92
Equity affiliates Canada		**17.64**	14.82	13.57
Taxes Other Than Income Taxes Per Barrel of Oil Equivalent*				
Consolidated operations				
Alaska	$	**33.11**	17.65	11.62
Lower 48		**3.33**	3.08	2.37
United States		**13.61**	8.26	5.65
Canada		**.88**	.91	.83
Europe		**.04**	.05	.02
Asia Pacific/Middle East		**6.56**	3.76	1.80
Africa		**.95**	.47	.47
Other areas		**-**	-	4.79
Total international		**2.25**	1.34	.74
Total consolidated operations		**7.44**	4.27	2.87
Equity affiliates				
Canada		**.24**	.22	.19
Russia		**70.85**	25.08	17.46
Asia Pacific/Middle East		**4.88**	3.69	.78
Total equity affiliates		**13.51**	20.97	15.69
Depreciation, Depletion and Amortization Per Barrel of Oil Equivalent*				
Consolidated operations				
Alaska	$	**5.69**	5.95	6.25
Lower 48		**13.55**	13.81	14.71

United States	**10.84**	11.02	11.71
Canada	**20.33**	20.38	18.73
Europe	**13.80**	15.58	14.27
Asia Pacific/Middle East	**11.35**	12.77	9.94
Africa	**7.76**	5.33	5.61
Other areas	**-**	-	7.53
Total international	**14.28**	14.82	13.40
Total consolidated operations	**12.71**	13.21	12.67
Equity affiliates			
Canada	**10.05**	10.62	8.47
Russia	**4.91**	4.11	3.24
Asia Pacific/Middle East	**3.34**	4.83	4.11
Total equity affiliates	**5.58**	4.86	3.67

**Includes bitumen.*

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Net Wells Completed[1]	Productive			Dry		
	2011	2010	2009	**2011**	2010	2009
Exploratory[2]						
Consolidated operations						
Alaska	**-**	-	-	**-**	-	2
Lower 48	**98**	23	33	**5**	1	14
United States	**98**	23	33	**5**	1	16
Canada	**8**	15	17	**3**	7	19
Europe	**1**	1	1	*****	*	2
Asia Pacific/Middle East	**1**	3	3	**1**	1	3
Africa	*****	1	*	*****	*	*
Total consolidated operations	**108**	43	54	**9**	9	40
Equity affiliates						
Russia	**-**	-	1	**-**	-	-
Asia Pacific/Middle East	**5**	2	-	**-**	-	-
Total equity affiliates[3]	**5**	2	1	**-**	-	-
Includes extension wells of:	***98***	*23*	*40*	***3***	*1*	*29*

	Productive			Dry		
	2011	2010	2009	**2011**	2010	2009
Development						
Consolidated operations						
Alaska	**41**	47	47	**-**	*	-
Lower 48	**350**	269	592	**4**	2	4
United States	**391**	316	639	**4**	2	4
Canada	**146**	186	227	**1**	12	20
Europe	**4**	6	9	**-**	-	-
Asia Pacific/Middle East	**30**	59	47	**-**	*	-
Africa	**5**	9	3	**-**	-	-
Total consolidated operations	**576**	576	925	**5**	14	24
Equity affiliates						
Canada	**157**	112	61	**-**	-	-
Russia	**3**	2	6	**-**	-	*
Asia Pacific/Middle East	**9**	25	28	**1**	-	-
Total equity affiliates[3]	**169**	139	95	**1**	-	*

(1) Excludes farmout arrangements.

(2) Includes extension wells, as well as other types of exploratory wells. Extension exploratory wells are either wells drilled in areas near or offsetting current production, or wells drilled in areas that have not yet achieved a well density and production history to achieve statistical certainty of results. These are classified

as exploratory wells because proved reserves cannot be attributed to these locations.

(3) Excludes LUKOIL.

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

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	00000000	00000000	00000000	00000000	00000000	00000000
Wells at December 31, 2011			Productive[2]			
	In Progress[1]		Oil		Gas	
	Gross	Net	Gross	Net	Gross	Net
Consolidated operations						
Alaska	24	12	1,902	860	35	22
Lower 48	296	218	9,133	4,393	24,793	15,624
United States	320	230	11,035	5,253	24,828	15,646
Canada	306[3]	211[3]	1,630	971	12,895	7,593
Europe	25	5	609	109	271	109
Asia Pacific/Middle East	62	25	467	200	114	52
Africa	103	17	1,151	201	12	2
Other areas	46	4	-	-	-	-
Total consolidated operations	862	492	14,892	6,734	38,120	23,402
Equity affiliates						
Canada	15	8	242	121	-	-
Russia	8	2	107	38	2	1
Asia Pacific/Middle East	1,015	220	-	-	521	140
Total equity affiliates	1,038	230	349	159	523	141

(1)Includes wells that have been temporarily suspended.

(2)Includes 5,883 gross and 3,734 net multiple completion wells.

(3)Includes 246 gross and 165 net stratigraphic test wells for oil sands projects.

	00000000	00000000	00000000	00000000
Acreage at December 31, 2011	Thousands of Acres			
	Developed		Undeveloped	
	Gross	Net	Gross	Net
Consolidated operations				
Alaska	650	329	1,440	1,197
Lower 48	7,012	5,244	10,286	8,790
United States	7,662	5,573	11,726	9,987
Canada	6,543	4,240	6,412	4,379
Europe	862	242	3,008	1,177
Asia Pacific/Middle East	4,123	1,777	19,585	11,989
Africa	528	132	14,730	2,575
Other areas	-	-	11,066	4,251
Total consolidated operations	19,718	11,964	66,527	34,358

Equity affiliates				
Canada	33	14	588	243
Russia	291	90	1,173	476
Asia Pacific/Middle East	1,129	250	8,140	2,750
Total equity affiliates	1,453	354	9,901	3,469

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Costs Incurred

Years Ended December 31	Millions of Dollars									
	Alaska	Lower 48	Total U.S.	Canada	Europe	Russia	Asia Pacific/ Middle East	Africa	Other Areas	Total
2011										
Consolidated operations										
Unproved property acquisition	$ 1	577	578	145	-	-	-	-	-	723
Proved property acquisition	-	10	10	-	-	-	36	-	-	46
	1	587	588	145	-	-	36	-	-	769
Exploration	84	1,031	1,115	269	201	1	226	63	88	1,963
Development	499	2,633	3,132	1,347	2,123	-	949	263	726	8,540
	$ 584	4,251	4,835	1,761	2,324	1	1,211	326	814	11,272
Equity affiliates										
Unproved property acquisition	$ -	-	-	-	-	-	484	-	-	484
Proved property acquisition	-	-	-	-	-	-	-	-	-	-
	-	-	-	-	-	-	484	-	-	484
Exploration	-	-	-	64	-	1	100	-	-	165
Development	-	-	-	911	-	43	632	-	-	1,586
	$ -	-	-	975	-	44	1,216	-	-	2,235
2010										
Consolidated operations										
Unproved property acquisition	$ (26)	286	260	113	9	-	-	-	-	382
Proved property acquisition	-	100	100	1	-	-	-	-	-	101
	(26)	386	360	114	9	-	-	-	-	483
Exploration	119	487	606	269	144	3	356	45	143	1,566
Development	588	1,439	2,027	927	1,351	-	858	375	729	6,267
	$ 681	2,312	2,993	1,310	1,504	3	1,214	420	872	8,316
Equity affiliates										
Unproved property acquisition*	$ -	-	-	81	-	15	379	-	-	475
Proved property acquisition*	-	-	-	-	-	173	-	-	-	173
	-	-	-	81	-	188	379	-	-	648
Exploration	-	-	-	-	-	92	123	-	-	215
Development	-	-	-	621	-	751	403	-	-	1,775
	$ -	-	-	702	-	1,031	905	-	-	2,638

* *Amounts in Asia Pacific/Middle East were reclassified between Unproved property acquisition and Proved property acquisition. Total acquisition costs were unchanged.*

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Years Ended	Millions of Dollars									
December 31	Alaska	Lower 48	Total U.S.	Canada	Europe	Russia	Asia Pacific/ Middle East	Africa	Other Areas	Total
2009										
Consolidated operations										
Unproved property acquisition	$ -	78	78	62	5	-	30	-	55	230
Proved property acquisition	1	6	7	7	-	-	-	-	-	14
	1	84	85	69	5	-	30	-	55	244
Exploration	137	476	613	251	184	4	342	33	90	1,517
Development	790	1,726	2,516	1,114	1,108	-	1,244	240	685	6,907
	$ 928	2,286	3,214	1,434	1,297	4	1,616	273	830	8,668
Equity affiliates										
Unproved property acquisition*	$ -	-	-	-	-	18	219	-	-	237
Proved property acquisition*	-	-	-	-	-	176	-	-	-	176
	-	-	-	-	-	194	219	-	-	413
Exploration	-	-	-	-	-	62	53	-	-	115
Development	-	-	-	446	-	820	376	-	-	1,642
	$ -	-	-	446	-	1,076	648	-	-	2,170

* *Amounts in Asia Pacific/Middle East were reclassified between Unproved property acquisition and Proved property acquisition. Total acquisition costs were unchanged.*

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Capitalized Costs

At December 31					Millions of Dollars					
	Alaska	Lower 48	Total U.S.	Canada	Europe	Russia	Asia Pacific/ Middle East	Africa	Other Areas	Total
2011										
Consolidated operations										
Proved properties	$ 12,770	34,939	47,709	19,578	22,948	8	12,284	3,867	4,650	111,044
Unproved properties	1,528	2,574	4,102	1,986	289	1	1,026	174	268	7,846
	14,298	37,513	51,811	21,564	23,237	9	13,310	4,041	4,918	118,890
Accumulated depreciation, depletion and amortization	6,237	15,464	21,701	10,599	14,451	7	5,626	1,559	12	53,955
	$ 8,061	22,049	30,110	10,965	8,786	2	7,684	2,482	4,906	64,935
Equity affiliates										
Proved properties	$ -	-	-	5,774	-	1,966	2,870	-	-	10,610
Unproved properties	-	-	-	1,657	-	146	7,182	-	-	8,985
	-	-	-	7,431	-	2,112	10,052	-	-	19,595
Accumulated depreciation, depletion and amortization	-	-	-	764	-	1,902	184	-	-	2,850
	$ -	-	-	6,667	-	210	9,868	-	-	16,745
2010										
Consolidated operations										
Proved properties	$ 12,268	32,076	44,344	20,037	21,547	9	11,199	3,595	3,921	104,652
Unproved properties	1,471	1,700	3,171	1,930	328	1	1,113	163	249	6,955
	13,739	33,776	47,515	21,967	21,875	10	12,312	3,758	4,170	111,607
Accumulated depreciation, depletion and amortization	5,758	13,362	19,120	10,281	13,636	7	4,690	1,370	10	49,114
	$ 7,981	20,414	28,395	11,686	8,239	3	7,622	2,388	4,160	62,493
Equity affiliates										
Proved properties	$ -	-	-	4,812	-	1,923	2,320	-	-	9,055
Unproved properties	-	-	-	1,794	-	146	8,144	-	-	10,084
	-	-	-	6,606	-	2,069	10,464	-	-	19,139
Accumulated depreciation, depletion and amortization	-	-	-	512	-	1,584	84	-	-	2,180
	$ -	-	-	6,094	-	485	10,380	-	-	16,959

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Standardized Measure of Discounted Future Net Cash Flows Relating to Proved Oil and Gas Reserve Quantities

In accordance with SEC and FASB requirements, amounts were computed using 12-month average prices and end-of-year costs (adjusted only for existing contractual changes), appropriate statutory tax rates and a prescribed 10 percent discount factor. Twelve-month average prices are calculated as the unweighted arithmetic average of the first-day-of-the-month price for each month within the 12-month period prior to the end of the reporting period. For all years, continuation of year-end economic conditions was assumed. The calculations were 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, were not considered. The calculations also require assumptions as to the timing of future production of proved reserves, and the timing and amount of future development, including dismantlement, and production costs.

While due care was taken in its preparation, we do not represent that this data is the fair value of our oil and gas properties, or a fair estimate of the present value of cash flows to be obtained from their development and production.

Discounted Future Net Cash Flows

	Millions of Dollars									
	Alaska	Lower 48	Total U.S.	Canada	Europe	Russia	Asia Pacific/ Middle East	Africa	Other Areas	Total
2011										
Consolidated operations										
Future cash inflows	$ 143,652	73,807	217,459	40,581	78,250	-	49,936	33,017	11,891	431,134
Less:										
Future production and transportation costs*	75,771	32,766	108,537	19,148	17,166	-	14,380	4,113	3,768	167,112
Future development costs	11,385	7,519	18,904	13,393	16,986	-	3,051	885	2,080	55,299
Future income tax provisions	20,512	11,771	32,283	2,060	29,853	-	11,967	23,825	990	100,978
Future net cash flows	35,984	21,751	57,735	5,980	14,245	-	20,538	4,194	5,053	107,745
10 percent annual discount	19,233	9,643	28,876	4,025	5,372	-	6,649	1,522	3,712	50,156
Discounted future net cash flows	$ 16,751	12,108	28,859	1,955	8,873	-	13,889	2,672	1,341	57,589
Equity affiliates										
Future cash inflows	$ -	-	-	53,618	-	2,786	43,327	-	-	99,731
Less:										
Future production and transportation costs*	-	-	-	16,405	-	2,765	24,702	-	-	43,872
Future development costs	-	-	-	7,163	-	36	905	-	-	8,104
Future income tax provisions	-	-	-	7,574	-	3	3,705	-	-	11,282
Future net cash flows	-	-	-	22,476	-	(18)	14,015	-	-	36,473
10 percent annual discount	-	-	-	14,662	-	(39)	7,217	-	-	21,840
Discounted future net cash flows	$ -	-	-	7,814	-	21	6,798	-	-	14,633

Total company											
Discounted future net cash flows	$	16,751	12,108	28,859	9,769	8,873	21	20,687	2,672	1,341	72,222

**Includes taxes other than income taxes.*

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		Millions of Dollars								
	Alaska	Lower 48*	Total U.S.	Canada	Europe	Russia	Asia Pacific/ Middle East	Africa	Other Areas	Total
2010										
Consolidated operations										
Future cash inflows	$ 102,743	68,949	171,692	38,083	49,270	-	37,673	24,487	8,466	329,671
Less:										
Future production and transportation costs**	57,899	29,749	87,648	16,753	12,899	-	10,480	4,142	3,007	134,929
Future development costs	8,792	7,752	16,544	11,161	10,295	-	2,226	1,133	3,050	44,409
Future income tax provisions	13,383	10,953	24,336	2,416	16,765	-	9,211	16,217	384	69,329
Future net cash flows	22,669	20,495	43,164	7,753	9,311	-	15,756	2,995	2,025	81,004
10 percent annual discount	10,723	10,046	20,769	3,890	2,597	-	4,889	1,025	2,368	35,538
Discounted future net cash flows	$ 11,946	10,449	22,395	3,863	6,714	-	10,867	1,970	(343)	45,466
Equity affiliates										
Future cash inflows	$ -	-	-	47,169	-	5,610	32,845	-	-	85,624
Less:										
Future production and transportation costs**	-	-	-	16,492	-	4,809	21,036	-	-	42,337
Future development costs	-	-	-	4,684	-	85	295	-	-	5,064
Future income tax provisions	-	-	-	6,649	-	(80)	2,082	-	-	8,651
Future net cash flows	-	-	-	19,344	-	796	9,432	-	-	29,572
10 percent annual discount	-	-	-	13,453	-	293	4,732	-	-	18,478
Discounted future net cash flows	$ -	-	-	5,891	-	503	4,700	-	-	11,094
Total company										
Discounted future net cash flows	$ 11,946	10,449	22,395	9,754	6,714	503	15,567	1,970	(343)	56,560

**Certain amounts have been restated to remove future development costs related to probable reserves.*
***Includes taxes other than income taxes.*

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	Millions of Dollars									
	Alaska	Lower 48	Total U.S.	Canada	Europe	Russia	Asia Pacific/ Middle East	Africa	Other Areas	Total
2009										
Consolidated operations										
Future cash inflows	$ 74,359	51,007	125,366	45,965	41,832	-	31,276	19,618	6,416	270,473
Less:										
Future production and transportation costs*	44,789	32,491	77,280	23,625	13,559	-	9,058	3,832	2,071	129,425
Future development costs	7,829	8,350	16,179	12,769	10,369	-	2,284	1,142	3,879	46,622
Future income tax provisions	7,519	2,992	10,511	2,183	10,676	-	7,288	12,396	71	43,125
Future net cash flows	14,222	7,174	21,396	7,388	7,228	-	12,646	2,248	395	51,301
10 percent annual discount	6,474	2,300	8,774	3,703	1,878	-	4,108	879	1,566	20,908
Discounted future net cash flows	$ 7,748	4,874	12,622	3,685	5,350	-	8,538	1,369	(1,171)	30,393
Equity affiliates										
Future cash inflows	$ -	-	-	36,540	-	69,277	19,420	-	-	125,237
Less:										
Future production and transportation costs*	-	-	-	13,689	-	49,874	13,891	-	-	77,454
Future development costs	-	-	-	4,481	-	7,795	350	-	-	12,626
Future income tax provisions	-	-	-	4,785	-	2,265	694	-	-	7,744
Future net cash flows	-	-	-	13,585	-	9,343	4,485	-	-	27,413
10 percent annual discount	-	-	-	9,512	-	4,002	2,018	-	-	15,532
Discounted future net cash flows	$ -	-	-	4,073	-	5,341	2,467	-	-	11,881
Total company										
Discounted future net cash flows	$ 7,748	4,874	12,622	7,758	5,350	5,341	11,005	1,369	(1,171)	42,274

**Includes taxes other than income taxes.*

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Sources of Change in Discounted Future Net Cash Flows

	Millions of Dollars								
	Consolidated Operations			Equity Affiliates			Total Company		
	2011	2010*	2009	**2011**	2010	2009	**2011**	2010*	2009
Discounted future net cash flows at the beginning of the year	$ **45,466**	30,393	24,548	**11,094**	11,881	3,033	**56,560**	42,274	27,581
Changes during the year									
Revenues less production and transportation costs for the year**	**(24,223)**	(22,296)	(18,460)	**(1,962)**	(3,083)	(2,793)	**(26,185)**	(25,379)	(21,253)
Net change in prices, and production and transportation costs**	**38,161**	39,532	19,208	**4,685**	3,478	14,386	**42,846**	43,010	33,594
Extensions, discoveries and improved recovery, less estimated future costs	**8,730**	4,517	2,312	**832**	297	1,342	**9,562**	4,814	3,654
Development costs for the year	**8,428**	5,617	6,148	**1,488**	1,758	1,623	**9,916**	7,375	7,771
Changes in estimated future development costs	**(8,374)**	(2,917)	(7,036)	**(1,508)**	(129)	(2,197)	**(9,882)**	(3,046)	(9,233)
Purchases of reserves in place, less estimated future costs	**19**	19	3	**-**	-	96	**19**	19	99
Sales of reserves in place, less estimated future costs	**(390)**	(3,729)	(75)	**(234)**	(5,405)	-	**(624)**	(9,134)	(75)
Revisions of previous quantity estimates***	**(1,938)**	3,062	5,149	**491**	372	(1,597)	**(1,447)**	3,434	3,552
Accretion of discount	**7,710**	5,000	3,972	**1,284**	1,404	365	**8,994**	6,404	4,337
Net change in income taxes	**(16,000)**	(13,732)	(5,376)	**(1,537)**	521	(2,377)	**(17,537)**	(13,211)	(7,753)
Total changes	**12,123**	15,073	5,845	**3,539**	(787)	8,848	**15,662**	14,286	14,693
Discounted future net cash flows at year end	$ **57,589**	45,466	30,393	**14,633**	11,094	11,881	**72,222**	56,560	42,274

**Certain amounts have been restated to remove future development costs related to probable reserves.*

***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 12-month average 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.

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Selected Quarterly Financial Data (Unaudited)

	Millions of Dollars				Per Share of Common Stock Net Income Attributable to ConocoPhillips	
	Sales and Other Operating Revenues*	Income Before Income Taxes	Net Income	Net Income Attributable to ConocoPhillips	Basic	Diluted
2011						
First	**$ 56,530**	**5,796**	**3,042**	**3,028**	**2.11**	**2.09**
Second	**65,627**	**6,192**	**3,419**	**3,402**	**2.43**	**2.41**
Third	**62,784**	**5,180**	**2,631**	**2,616**	**1.93**	**1.91**
Fourth	**59,872**	**5,833**	**3,410**	**3,390**	**2.58**	**2.56**
2010						
First	$ 44,821	3,990	2,112	2,098	1.41	1.40
Second	45,686	6,194	4,183	4,164	2.79	2.77
Third	47,208	5,274	3,069	3,055	2.06	2.05
Fourth	51,726	4,292	2,053	2,041	1.40	1.39

**Includes excise taxes on petroleum products sales.*

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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, ConocoPhillips Canada Funding Company I and ConocoPhillips Canada Funding Company II are indirect, wholly owned subsidiaries of ConocoPhillips Company. 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 February 2009, 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.

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	ConocoPhillip	ConocoPhillip	ConocoPhillip	ConocoPhillip	ConocoPhillip	ConocoPhillip	ConocoPhillip	ConocoPhillip
				Millions of Dollars Year Ended December 31, 2011				
Income Statement	ConocoPhillips	ConocoPhillips Company	ConocoPhillips Australia Funding Company	ConocoPhillips Canada Funding Company I	ConocoPhillips Canada Funding Company II	All Other Subsidiaries	Consolidating Adjustments	Total Consolidated
Revenues and Other Income								
Sales and other operating revenues	$ -	150,422	-	-	-	94,391	-	244,813
Equity in earnings of affiliates	13,478	15,025	-	-	-	2,219	(26,645)	4,077
Gain (loss) on dispositions	-	(117)	-	-	-	2,124	-	2,007
Other income	-	108	-	-	-	221	-	329
Intercompany revenues	4	4,355	46	91	35	37,603	(42,134)	-
Total Revenues and Other Income	13,482	169,793	46	91	35	136,558	(68,779)	251,226
Costs and Expenses								
Purchased crude oil, natural gas and products	-	140,833	-	-	-	85,427	(40,393)	185,867
Production and operating expenses	-	4,446	-	-	-	6,543	(219)	10,770
Selling, general and administrative expenses	13	1,393	-	-	-	625	47	2,078
Exploration expenses	-	329	-	-	-	734	3	1,066
Depreciation, depletion and amortization	-	1,532	-	-	-	6,402	-	7,934
Impairments	-	506	-	-	-	286	-	792
Taxes other than income taxes	-	5,092	-	-	-	13,217	(2)	18,307
Accretion on discounted liabilities	-	69	-	-	-	386	-	455
Interest and debt expense	1,594	424	42	77	32	373	(1,570)	972
Foreign currency transaction (gains) losses	-	(17)	-	(10)	(35)	46	-	(16)
Total Costs and Expenses	1,607	154,607	42	67	(3)	114,039	(42,134)	228,225

Income before income taxes		11,875	15,186	4	24	38	22,519	(26,645)	23,001
Provision for income taxes		(561)	1,708	1	(1)	12	9,340	-	10,499
Net income		12,436	13,478	3	25	26	13,179	(26,645)	12,502
Less: net income attributable to noncontrolling interests		-	-	-	-	-	(66)	-	(66)
Net Income Attributable to ConocoPhillips	$	12,436	13,478	3	25	26	13,113	(26,645)	12,436

		ConocoPhillip	ConocoPhillip	ConocoPhillip	ConocoPhillip	ConocoPhillip	ConocoPhillip	ConocoPhillip	ConocoPhillip
Income Statement					Year Ended December 31, 2010				
Revenues and Other Income									
Sales and other operating revenues	$	-	116,220	-	-	-	73,221	-	189,441
Equity in earnings of affiliates		11,977	13,433	-	-	-	2,195	(24,472)	3,133
Gain on dispositions		-	388	-	-	-	5,415	-	5,803
Other income (loss)		1	275	-	-	(28)	30	-	278
Intercompany revenues		5	1,394	46	86	66	25,971	(27,568)	-
Total Revenues and Other Income		11,983	131,710	46	86	38	106,832	(52,040)	198,655
Costs and Expenses									
Purchased crude oil, natural gas and products		-	105,105	-	-	-	57,091	(26,445)	135,751
Production and operating expenses		-	4,646	-	-	-	6,087	(98)	10,635
Selling, general and administrative expenses		12	1,392	-	-	-	629	(28)	2,005
Exploration expenses		-	247	-	-	-	908	-	1,155
Depreciation, depletion and amortization		-	1,597	-	-	-	7,463	-	9,060
Impairments		-	51	-	-	-	1,729	-	1,780
Taxes other than income taxes		-	5,157	-	-	-	11,638	(2)	16,793
Accretion on discounted liabilities		-	63	-	-	-	384	-	447
Interest and debt expense		946	475	42	77	45	597	(995)	1,187

Foreign currency transaction (gains) losses		-	20	-	47	50	(25)	-	92
Total Costs and Expenses		958	118,753	42	124	95	86,501	(27,568)	178,905
Income (loss) before income taxes		11,025	12,957	4	(38)	(57)	20,331	(24,472)	19,750
Provision for income taxes		(333)	980	1	7	(6)	7,684	-	8,333
Net income (loss)		11,358	11,977	3	(45)	(51)	12,647	(24,472)	11,417
Less: net income attributable to noncontrolling interests		-	-	-	-	-	(59)	-	(59)
Net Income (Loss) Attributable to ConocoPhillips	$	11,358	11,977	3	(45)	(51)	12,588	(24,472)	11,358

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	Millions of Dollars Year Ended December 31, 2009							
Income Statement	ConocoPhillips	ConocoPhillips Company	ConocoPhillips Australia Funding Company	ConocoPhillips Canada Funding Company I	ConocoPhillips Canada Funding Company II	All Other Subsidiaries	Consolidating Adjustments	Total Consolidated
Revenues and Other Income								
Sales and other operating revenues	$ -	90,916	-	-	-	58,425	-	149,341
Equity in earnings of affiliates	4,815	5,459	-	-	-	1,666	(9,409)	2,531
Gain on dispositions	-	157	-	-	-	3	-	160
Other income (loss)	-	396	-	-	-	(38)	-	358
Intercompany revenues	30	1,119	51	78	48	18,478	(19,804)	-
Total Revenues and Other Income	4,845	98,047	51	78	48	78,534	(29,213)	152,390
Costs and Expenses								
Purchased crude oil, natural gas and products	-	80,280	-	-	-	41,122	(18,969)	102,433
Production and operating expenses	2	4,421	-	-	-	6,013	(97)	10,339
Selling, general and administrative expenses	15	1,194	-	-	-	639	(18)	1,830
Exploration expenses	-	295	-	-	-	887	-	1,182
Depreciation, depletion and amortization	-	1,710	-	-	-	7,585	-	9,295
Impairments	-	63	-	-	-	472	-	535
Taxes other than income taxes	-	4,875	-	-	-	10,674	(20)	15,529
Accretion on discounted liabilities	-	59	-	-	-	363	-	422
Interest and debt expense	631	155	46	77	53	1,027	(700)	1,289
Foreign currency transaction (gains) losses	-	(35)	-	171	216	(398)	-	(46)
Total Costs and Expenses	648	93,017	46	248	269	68,384	(19,804)	142,808
Income (loss) before income taxes	4,197	5,030	5	(170)	(221)	10,150	(9,409)	9,582
Provision for income taxes	(217)	215	2	4	(24)	5,110	-	5,090
Net income (loss)	4,414	4,815	3	(174)	(197)	5,040	(9,409)	4,492
Less: net income attributable to noncontrolling interests	-	-	-	-	-	(78)	-	(78)
Net Income (Loss) Attributable to ConocoPhillips	$ 4,414	4,815	3	(174)	(197)	4,962	(9,409)	4,414

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	ConocoPhillip	ConocoPhillip	ConocoPhillip	ConocoPhillip	ConocoPhillip	ConocoPhillip	ConocoPhillip	ConocoPhillip
	Millions of Dollars At December 31, 2011							
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	$ -	2,028	1	37	1	3,713	-	5,780
Short-term investments	-	-	-	-	-	581	-	581
Accounts and notes receivable	60	9,186	-	-	-	20,898	(13,618)	16,526
Inventories	-	2,239	-	-	-	2,392	-	4,631
Prepaid expenses and other current assets	22	1,090	-	1	-	1,587	-	2,700
Total Current Assets	82	14,543	1	38	1	29,171	(13,618)	30,218
Investments, loans and long-term receivables*	96,269	135,603	760	1,417	565	59,651	(260,482)	33,783
Net properties, plants and equipment	-	19,595	-	-	-	64,585	-	84,180
Goodwill	-	3,332	-	-	-	-	-	3,332
Intangibles	-	722	-	-	-	23	-	745
Other assets	64	301	-	2	3	602	-	972
Total Assets	$ 96,415	174,096	761	1,457	569	154,032	(274,100)	153,230
Liabilities and Stockholders Equity								
Accounts payable	$ 10	18,747	-	1	1	14,512	(13,618)	19,653
Short-term debt	892	27	-	-	-	94	-	1,013
Accrued income and other taxes	-	315	-	2	-	3,903	-	4,220
Employee benefit obligations	-	835	-	-	-	276	-	1,111
Other accruals	244	634	9	14	6	1,164	-	2,071
Total Current Liabilities	1,146	20,558	9	17	7	19,949	(13,618)	28,068
Long-term debt	10,951	3,599	749	1,250	498	4,563	-	21,610
Asset retirement obligations and accrued environmental costs	-	1,766	-	-	-	7,563	-	9,329

Joint venture acquisition obligation	-	-	-	-	-	3,582	-	3,582
Deferred income taxes	(5)	3,982	-	11	9	14,058	-	18,055
Employee benefit obligations	-	3,092	-	-	-	976	-	4,068
Other liabilities and deferred credits*	25,959	40,479	-	104	29	20,047	(83,834)	2,784
Total Liabilities	38,051	73,476	758	1,382	543	70,738	(97,452)	87,496
Retained earnings	42,694	35,065	1	(70)	(55)	29,928	(58,369)	49,194
Other common stockholders equity	15,670	65,555	2	145	81	52,856	(118,279)	16,030
Noncontrolling interests	-	-	-	-	-	510	-	510
Total Liabilities and Stockholders Equity	$ 96,415	174,096	761	1,457	569	154,032	(274,100)	153,230

**Includes intercompany loans.*

alance Sheet	ConocoPhillip	ConocoPhillip	ConocoPhillip	ConocoPhillip	ConocoPhillip	ConocoPhillip	ConocoPhillip	ConocoPhillip
				At December 31, 2010				
ssets								
Cash and cash equivalents	$ -	718	-	29	4	8,703	-	9,454
hort-term investments	-	-	-	-	-	973	-	973
Accounts and notes receivable	36	9,126	1	-	-	16,625	(9,976)	15,812
nvestment in LUKOIL	-	-	-	-	-	1,083	-	1,083
nventories	-	3,121	-	-	-	2,076	-	5,197
repaid expenses and other current ssets	23	824	-	2	-	1,292	-	2,141
otal Current Assets	59	13,789	1	31	4	30,752	(9,976)	34,660
nvestments, loans and long-term eceivables*	84,446	111,993	762	1,445	577	50,563	(216,025)	33,761
et properties, plants and equipment	-	19,524	-	-	-	63,030	-	82,554
oodwill	-	3,633	-	-	-	-	-	3,633
ntangibles	-	760	-	-	-	41	-	801
ther assets	55	254	1	3	3	589	-	905
otal Assets	$ 84,560	149,953	764	1,479	584	144,975	(226,001)	156,314
iabilities and Stockholders Equity								
Accounts payable	$ -	14,939	-	2	-	13,434	(9,976)	18,399
hort-term debt	(5)	354	-	-	-	587	-	936
ccrued income and other taxes	-	431	-	-	6	4,437	-	4,874
mployee benefit obligations	-	773	-	-	-	308	-	1,081
ther accruals	242	620	9	15	6	1,237	-	2,129
otal Current Liabilities	237	17,117	9	17	12	20,003	(9,976)	27,419
ong-term debt	11,832	3,674	750	1,250	499	4,651	-	22,656
sset retirement obligations and ccrued environmental costs	-	1,686	-	-	-	7,513	-	9,199
oint venture acquisition obligation	-	-	-	-	-	4,314	-	4,314
eferred income taxes	(1)	3,659	-	16	(2)	13,663	-	17,335
mployee benefit obligations	-	2,779	-	-	-	904	-	3,683
ther liabilities and deferred credits*	10,752	32,268	-	114	61	19,169	(59,765)	2,599

otal Liabilities		22,820	61,183	759	1,397	570	70,217	(69,741)	87,205
etained earnings		33,897	21,584	3	(94)	(81)	20,162	(35,074)	40,397
ther common stockholders equity		27,843	67,186	2	176	95	54,049	(121,186)	28,165
oncontrolling interests		-	-	-	-	-	547	-	547
otal Liabilities and Stockholders quity	$	84,560	149,953	764	1,479	584	144,975	(226,001)	156,314

Includes intercompany loans.

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	ConocoPhillips	ConocoPhillips	ConocoPhillips	ConocoPhillips	ConocoPhillips	ConocoPhillips	ConocoPhillips	ConocoPhil
				Millions of Dollars Year Ended December 31, 2011				
ment 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	T Consolid
Flows From Operating Activities								
ash Provided by (Used in) Operating ties	$ 14,669	(4,164)	1	13	(7)	12,478	(3,344)	19
Flows From Investing Activities								
al expenditures and investments	-	(2,221)	-	-	-	(11,045)	-	(13
eds from asset dispositions	-	2,807	-	-	-	2,013	-	4
les of short-term investments	-	-	-	-	-	400	-	
term advances/loans related parties	-	(916)	-	(4)	-	(5,926)	6,837	
ction of advances/loans related s	-	1,543	-	-	-	1,504	(2,399)	
	-	60	-	-	-	332	-	
ash Provided by (Used in) Investing ties	-	1,273	-	(4)	-	(12,722)	4,438	(7
Flows From Financing Activities								
ce of debt	-	5,922	-	-	4	911	(6,837)	
ment of debt	-	(1,839)	-	-	-	(1,521)	2,399	(
ce of company common stock	96	-	-	-	-	-	-	
chase of company common stock	(11,123)	-	-	-	-	-	-	(11
ends paid on common stock	(3,633)	-	-	-	-	(3,343)	3,344	(3
	(9)	119	-	-	-	(795)	-	(
ash Provided by (Used in) cing Activities	(14,669)	4,202	-	-	4	(4,748)	(1,094)	(16
t of Exchange Rate Changes on ash and Cash Equivalents	-	(1)	-	-	-	1	-	
hange in Cash and Cash alents	-	1,310	1	9	(3)	(4,991)	-	(3
and cash equivalents at beginning of	-	718	-	29	4	8,703	-	9
and Cash Equivalents at End of Year	$ -	2,028	1	38	1	3,712	-	5

ment of Cash Flows	ConocoPhillips	ConocoPhillips	ConocoPhillips	ConocoPhillips Year Ended December 31, 2010	ConocoPhillips	ConocoPhillips	ConocoPhillips	ConocoPhi
Flows From Operating Activities								
ash Provided by (Used in) ing Activities	$ 7,901	2,311	-	11	(3)	9,338	(2,513)	17

Flows From Investing Activities								
l expenditures and investments	-	(1,863)	-	-	-	(8,221)	323	(9
ds from asset dispositions	-	781	-	-	-	14,690	(99)	15
rchases of short-term investments	-	-	-	-	-	(982)	-	
erm advances/loans related parties	-	(335)	-	-	-	(2,279)	2,301	
tion of advances/loans related	-	107	-	-	384	1,379	(1,755)	
	-	28	-	-	-	206	-	
sh Provided by (Used in) Investing ties	-	(1,282)	-	-	384	4,793	770	4
Flows From Financing Activities								
ce of debt	-	2,159	-	-	-	260	(2,301)	
ment of debt	(990)	(2,660)	-	-	(378)	(3,047)	1,755	(5
ce of company common stock	133	-	-	-	-	-	-	
chase of company common stock	(3,866)	-	-	-	-	-	-	(3
nds paid on common stock	(3,175)	-	-	-	-	(2,666)	2,666	(3
	(3)	52	-	-	-	(534)	(224)	
sh Provided by (Used in) ing Activities	(7,901)	(449)	-	-	(378)	(5,987)	1,896	(12
of Exchange Rate Changes on and Cash Equivalents	-	16	-	-	-	5	-	
hange in Cash and Cash alents	-	596	-	11	3	8,149	153	8
nd cash equivalents at beginning of	-	122	-	18	1	554	(153)	
nd Cash Equivalents at End of	$ -	718	-	29	4	8,703	-	9

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	Millions of Dollars Year Ended December 31, 2009							
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	$ (2,205)	6,451	-	8	-	10,309	(2,084)	12,479
Cash Flows From Investing Activities								
Capital expenditures and investments	-	(3,157)	-	-	-	(8,384)	680	(10,861)
Proceeds from asset dispositions	-	629	-	-	-	960	(319)	1,270
Long-term advances/loans related parties	-	(425)	-	-	-	(681)	581	(525)
Collection of advances/loans related parties	-	168	950	-	-	3,808	(4,833)	93
Other	-	46	-	-	-	42	-	88
Net Cash Provided by (Used in) Investing Activities	-	(2,739)	950	-	-	(4,255)	(3,891)	(9,935)
Cash Flows From Financing Activities								
Issuance of debt	8,909	490	-	-	-	269	(581)	9,087
Repayment of debt	(3,826)	(4,106)	(950)	-	-	(3,809)	4,833	(7,858)
Issuance of company common stock	13	-	-	-	-	-	-	13
Dividends paid on common stock	(2,832)	-	-	-	-	(1,945)	1,945	(2,832)
Other	(59)	18	-	-	-	(863)	(361)	(1,265)
Net Cash Provided by (Used in) Financing Activities	2,205	(3,598)	(950)	-	-	(6,348)	5,836	(2,855)
Effect of Exchange Rate Changes on Cash and Cash Equivalents	-	-	-	-	-	98	-	98
Net Change in Cash and Cash Equivalents	-	114	-	8	-	(196)	(139)	(213)
Cash and cash equivalents at beginning of year	-	8	-	10	1	750	(14)	755
Cash and Cash Equivalents at End of Year	$ -	122	-	18	1	554	(153)	542

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

None.

Item 9A. CONTROLS AND PROCEDURES

As of December 31, 2011, with the participation of our management, our Chairman, President 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 ConocoPhillips disclosure controls and procedures (as defined in Rule 13a-15(e) of the Act). Based upon that evaluation, our Chairman, President 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, 2011.

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, 2011, 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.

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PART III

Item 10. DIRECTORS, EXECUTIVE OFFICERS AND CORPORATE GOVERNANCE

Information regarding our executive officers appears in Part I of this report on pages 35 and 36.

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). 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 2012 Annual Meeting of Stockholders, to be filed pursuant to Regulation 14A on or before April 29, 2012, 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 2012 Annual Meeting of Stockholders, to be filed pursuant to Regulation 14A on or before April 29, 2012, 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 2012 Annual Meeting of Stockholders, to be filed pursuant to Regulation 14A on or before April 29, 2012, 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 2012 Annual Meeting of Stockholders, to be filed pursuant to Regulation 14A on or before April 29, 2012, 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 2012 Annual Meeting of Stockholders, to be filed pursuant to Regulation 14A on or before April 29, 2012, 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 2012 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.*

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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 176 through 180 are filed as part of this annual report.

SCHEDULE

VALUATION AND QUALIFYING ACCOUNTS

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
2011						
Deducted from asset accounts:						
Allowance for doubtful accounts and notes receivable	**$**	**32**	**2**	**-**	**(4)(b)**	**30**
Deferred tax asset valuation allowance		**1,400**	**174**	**(31)**	**(56)**	**1,487**
Included in other liabilities:						
Restructuring accruals		**105**	**25**	**(1)**	**(81)(c)**	**48**
2010						
Deducted from asset accounts:						
Allowance for doubtful accounts and notes receivable	$	76	(31)	(1)	(12)(b)	32
Deferred tax asset valuation allowance		1,540	414	(12)	(542)	1,400
Included in other liabilities:						
Restructuring accruals		73	78	1	(47)(c)	105
2009						
Deducted from asset accounts:						

Allowance for doubtful accounts and notes receivable	$	61	69	2	(56)(b)	76
Deferred tax asset valuation allowance		1,340	200	2	(2)	1,540
Included in other liabilities:						
Restructuring accruals		196	41	(76)	(88)(c)	73

(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.

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CONOCOPHILLIPS

INDEX TO EXHIBITS

Exhibit Number	Description
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	Amended and Restated By-Laws of ConocoPhillips, as amended and restated as of February 10, 2012 (incorporated by reference to Exhibit 3.1 to the Current Report of ConocoPhillips on Form 8-K filed on February 16, 2012; 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	1986 Stock Plan of Phillips Petroleum Company (incorporated by reference to Exhibit 10.11 to the Annual Report of ConocoPhillips on Form 10-K for the year ended December 31, 2002; File No. 000-49987).
10.2	1990 Stock Plan of Phillips Petroleum Company (incorporated by reference to Exhibit 10.12 to the Annual Report of ConocoPhillips on Form 10-K for the year ended December 31, 2002; File No. 000-49987).
10.3	Annual Incentive Compensation Plan of Phillips Petroleum Company (incorporated by reference to Exhibit 10.13 to the Annual Report of ConocoPhillips on Form 10-K for the year ended December 31, 2002; File No. 000-49987).
10.4	Incentive Compensation Plan of Phillips Petroleum Company (incorporated by reference to Exhibit 10(g) to the Annual Report of ConocoPhillips Company on Form 10-K for the year ended December 31, 1999; File No. 1-720).
10.5	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).

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Exhibit Number	Description
10.6	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).
10.7	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).
10.8	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).
10.9	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).
10.10.1	ConocoPhillips Key Employee Supplemental Retirement Plan (incorporated by reference to Exhibit 10.11 to the Annual Report of ConocoPhillips on Form 10-K for the year ended December 31, 2008; File No. 001-32395).
10.10.2	First Amendment to the ConocoPhillips Key Employee Supplemental Retirement Plan (incorporated by reference to Exhibit 10.10.2 to the Annual Report of ConocoPhillips on Form 10-K for the year ended December 31, 2010; File No. 001-32395).
10.11.1	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).
10.11.2	Defined Contribution Make-Up Plan of ConocoPhillips Title II (incorporated by reference to Exhibit 10.12.2 to the Annual Report of ConocoPhillips on Form 10-K for the year ended December 31, 2008; File No. 001-32395).
10.12	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).
10.13	1998 Stock and Performance Incentive Plan of ConocoPhillips (incorporated by reference to Exhibit 10.27 to the Annual Report of ConocoPhillips on Form 10-K for the year ended December 31, 2002; File No. 000-49987).
10.14	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).
10.15	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).

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Exhibit Number	Description
10.16	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).
10.17.1	Rabbi Trust Agreement dated December 17, 1999 (incorporated by reference to Exhibit 10.11 of the Annual Report of ConocoPhillips Holding Company on Form 10-K for the year ended December 31, 1999; File No. 001-14521).
10.17.2	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).
10.18.1	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).
10.18.2	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).
10.19	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).
10.20.1	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).
10.20.2	Key Employee Deferred Compensation Plan of ConocoPhillips Title II (incorporated by reference to Exhibit 10.21.2 to the Annual Report of ConocoPhillips on Form 10-K for the year ended December 31, 2008; File No. 001-32395).
10.20.3	First Amendment to the Key Employee Deferred Compensation Plan of ConocoPhillips Title II (incorporated by reference to Exhibit 10.20.3 to the Annual Report of ConocoPhillips on Form 10-K for the year ended December 31, 2010; File No. 001-32395).
10.20.4	Second Amendment to the Key Employee Deferred Compensation Plan of ConocoPhillips Title II (incorporated by reference to Exhibit 10.20.4 to the Annual Report of ConocoPhillips on Form 10-K for the year ended December 31, 2010; File No. 001-32395).
10.21	ConocoPhillips Key Employee Change in Control Severance Plan (incorporated by reference to Exhibit 10.22 to the Annual Report of ConocoPhillips on Form 10-K for the year ended December 31, 2008; File No. 001-32395).
10.22	ConocoPhillips Executive Severance Plan (incorporated by reference to Exhibit 10.23 to the Annual Report of ConocoPhillips on Form 10-K for the year ended December 31, 2008; File No. 001-32395).

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Exhibit Number	Description
10.23	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).
10.24	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).
10.25	Form of Stock Option Award Agreement under the ConocoPhillips Stock Option and Stock Appreciation Rights Program (incorporated by reference to Exhibit 10.26 to the Annual Report of ConocoPhillips on Form 10-K for the year ended December 31, 2008; File No. 001-32395).
10.26	Form of Restricted Stock Unit Award Agreement under the ConocoPhillips Performance Share Program (incorporated by reference to Exhibit 10.27 to the Annual Report of ConocoPhillips on Form 10-K for the year ended December 31, 2008; File No. 001-32395).
10.27	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).
10.28	Annex to Nonqualified Deferred Compensation Arrangements of ConocoPhillips (incorporated by reference to Exhibit 10.30 to the Annual Report of ConocoPhillips on Form 10-K for the year ended December 31, 2008; File No. 001-32395).
10.29.1	2009 Omnibus Stock and Performance Incentive Plan of ConocoPhillips (incorporated by reference to Appendix A of ConocoPhillips Proxy Statement on Schedule 14A relating to the 2009 Annual Meeting of Shareholders; File No. 001-32395).
10.29.2	2011 Omnibus Stock and Performance Incentive Plan of ConocoPhillips (incorporated by reference to Appendix A of ConocoPhillips Proxy Statement on Schedule 14A relating to the 2011 Annual Meeting of Shareholders; File No. 001-32395).
10.30	Offer letter from ConocoPhillips to Alan J. Hirshberg, dated October 2, 2010 (incorporated by reference to Exhibit 10 to the Quarterly Report of ConocoPhillips on Form 10-Q for the quarter ended March 31, 2011; File No. 001-32395).
12*	Computation of Ratio of Earnings to Fixed Charges.
21*	List of Subsidiaries of ConocoPhillips.
23.1*	Consent of Ernst & Young LLP.
23.2*	Consent of DeGolyer and MacNaughton.
31.1*	Certification of Chief Executive Officer pursuant to Rule 13a-14(a) under the Securities Exchange Act of 1934.
31.2*	Certification of Chief Financial Officer pursuant to Rule 13a-14(a) under the Securities Exchange Act of 1934.
32*	Certifications pursuant to 18 U.S.C. Section 1350.
99*	Report of DeGolyer and MacNaughton.

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Exhibit Number	Description
101.INS*	XBRL Instance Document.
101.SCH*	XBRL Schema Document.
101.CAL*	XBRL Calculation Linkbase Document.
101.DEF*	XBRL Definition Linkbase Document.
101.LAB*	XBRL Labels Linkbase Document.
101.PRE*	XBRL Presentation Linkbase Document.

* Filed herewith.

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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 21, 2012

/s/ James J. Mulva
James J. Mulva

Chairman of the Board of Directors, President

and Chief Executive Officer

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed, as of February 21, 2012, on behalf of the registrant by the following officers in the capacity indicated and by a majority of directors.

Signature	Title
/s/ James J. Mulva *James J. Mulva*	Chairman of the Board of Directors, President and Chief Executive Officer (Principal executive officer)
/s/ Jeff W. Sheets *Jeff W. Sheets*	Senior Vice President, Finance and Chief Financial Officer (Principal financial officer)
/s/ Glenda M. Schwarz *Glenda M. Schwarz*	Vice President and Controller (Principal accounting officer)

/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/ Mohd H. Marican *Mohd H. Marican*	Director
/s/ Harold W. McGraw III *Harold W. McGraw III*	Director
/s/ Robert A. Niblock *Robert A. Niblock*	Director
/s/ Harald J. Norvik *Harald J. Norvik*	Director
/s/ William K. Reilly *William K. Reilly*	Director
/s/ Victoria J. Tschinkel *Victoria J. Tschinkel*	Director
/s/ Kathryn C. Turner *Kathryn C. Turner*	Director
/s/ William E. Wade, Jr. *William E. Wade, Jr.*	Director