ConocoPhillips

2008 Annual Report

Managing Global Challenges

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Who We Are

Our Company

ConocoPhillips is an international, integrated energy company. It is the third-largest integrated energy company in the United States based on market capitalization and oil and natural gas proved reserves and production and the second-largest refiner. Worldwide, of nongovernment-controlled companies, ConocoPhillips is the sixth-largest proved reserves holder and the fourth-largest refiner.

The company is known worldwide for its technological expertise in exploration and production, reservoir management and exploitation, 3-D seismic technology, high-grade petroleum coke, its E-Gas™ coal gasification process and its Optimized Cascade process to produce liquefied natural gas.

Headquartered in Houston, Texas, ConocoPhillips operates in more than 30 countries. The company had 33,800 employees worldwide and assets of $143 billion as of Dec. 31, 2008. ConocoPhillips stock is listed on the New York Stock Exchange under the symbol "COP."

Our Businesses

The company has four core activities worldwide:

- Petroleum exploration and production.
- Petroleum refining, marketing, supply and transportation.
- Natural gas gathering, processing and marketing, including a 50 percent interest in DCP Midstream, LLC.
- Chemicals and plastics production and distribution through a 50 percent interest in Chevron Phillips Chemical Company LLC.

In addition, the company is investing in several emerging businesses – power generation, carbon-to-liquids, technology solutions, and emerging technologies such as renewable fuels and alternative energy sources – that provide current and potential future growth opportunities.

Our Theme

Managing Global Challenges

Like the entire energy industry, ConocoPhillips was impacted by extraordinary economic and commodity price volatility during 2008. After reaching record heights, oil prices declined precipitously late in the year as an international financial crisis triggered a global recession that in turn reduced energy demand.

ConocoPhillips intends to manage the global challenges posed by the downturn by exercising the consistent strategies that have transformed our company into a self-sustaining, competitive international, integrated energy firm. We will practice diligent financial management, conserve capital, strive to contain costs and utilize our operating expertise to maximize the value of our asset portfolio. That portfolio offers years of ongoing development potential in both our upstream and downstream businesses, in oil and natural gas, and in domestic and international locations.

In keeping with plans to live within our means during the current economic downturn, ConocoPhillips will conduct a disciplined capital investment program totaling $12.5 billion for 2009, a significant reduction from 2008. This measured approach is intended to preserve the company's high liquidity, flexibility and credit capability.

Progress continues on those major development projects that offer the greatest potential to drive the company's future growth. On projects that have been deferred, we retain the option of resuming or accelerating work when economic conditions improve.

We remain confident of our ability to maintain current levels of production while fully replacing reserves over the long term.

Financial Highlights

	Millions of Dollars Except as Indicated		
	2008	2007	% Change
Financial			
Total revenues and other income	**$ 246,182**	194,495	27%
Net income (loss)	**$ (16,998)**	11,891	(243)
Net income (loss) per share of common stock — diluted	**$ (11.16)**	7.22	(255)
Net cash provided by operating activities	**$ 22,658**	24,550	(8)
Capital expenditures and investments	**$ 19,099**	11,791	62
Total assets	**$ 142,865**	177,757	(20)
Total debt	**$ 27,455**	21,687	27
Minority interests	**$ 1,100**	1,173	(6)
Common stockholders' equity	**$ 55,165**	88,983	(38)
Percent of total debt to capital*	**33%**	19	74
Common stockholders' equity per share (book value)	**$ 37.27**	56.63	(34)
Cash dividends per common share	**$ 1.88**	1.64	15
Closing stock price per common share	**$ 51.80**	88.30	(41)
Common shares outstanding at year end (in thousands)	**1,480,179**	1,571,430	(6)
Average common shares outstanding (in thousands)			
Basic	**1,523,432**	1,623,994	(6)
Diluted	**1,523,432**	1,645,919	(7)
Employees at year end (in thousands)	**33.8**	32.6	4

**Capital includes total debt, minority interests and common stockholders' equity.*

	2008	2007	% Change
Operating*			
U.S. crude oil production (MBD)	**335**	363	(8)%
Worldwide crude oil production (MBD)	**806**	854	(6)
U.S. natural gas production (MMCFD)	**2,091**	2,292	(9)
Worldwide natural gas production (MMCFD)	**4,847**	5,087	(5)
Worldwide natural gas liquids production (MBD)	**153**	155	(1)
Worldwide Syncrude production (MBD)	**22**	23	(4)
LUKOIL Investment net production (MBOED)**	**445**	444	–
Worldwide production (MBOED)***	**2,234**	2,324	(4)
Natural gas liquids extracted — Midstream (MBD)	**188**	211	(11)
Worldwide refinery crude oil throughput (MBD)	**2,416**	2,560	(6)
Worldwide refinery utilization rate	**90%**	94	(4)
U.S. automotive gasoline sales (MBD)	**1,128**	1,244	(9)
U.S. distillates sales (MBD)	**893**	872	2
Worldwide petroleum products sales (MBD)	**3,040**	3,245	(6)
LUKOIL Investment refinery crude oil throughput (MBD)**	**229**	214	7

**Includes ConocoPhillips' share of equity affiliates, except LUKOIL, unless otherwise indicated.*
***Represents ConocoPhillips' net share of its estimate of LUKOIL's production and processing.*
****Includes Syncrude and ConocoPhillips' estimated share of LUKOIL's production.*

Certain disclosures in this Annual Report may be considered "forward-looking" statements. These are made pursuant to "safe harbor" provisions of the Private Securities Litigation Reform Act of 1995. The "Cautionary Statement" in Management's Discussion and Analysis on page 52 should be read in conjunction with such statements.

Use of Non-GAAP Financial Information – This Annual Report includes the terms "adjusted earnings" and "adjusted earnings per share." These are non-GAAP financial measures and are included to help facilitate comparisons of company operating performance across periods. A reconciliation of adjusted earnings to net income determined in accordance with U.S. generally accepted accounting principles (GAAP) is shown on page 112.

"ConocoPhillips," "the company," "we," "us" and "our" are used interchangeably in this report to refer to the businesses of ConocoPhillips and its consolidated subsidiaries.

Letter to Shareholders

Managing Global Challenges

To Our Shareholders:

James J. Mulva
Chairman and Chief Executive Officer

John A. Carrig
President and Chief Operating Officer

ConocoPhillips navigated through a challenging 2008, a year in which significant achievements by our company were overshadowed by a global economic crisis and unprecedented market volatility. We operated safely and reliably, expanded our global opportunity portfolio and returned substantial cash flow to shareholders through share repurchases and dividends.

Oil prices rose to record levels exceeding $140 per barrel in July, prompting intense public and political scrutiny and several governmental investigations and hearings. However, in the third quarter the rapidly worsening financial crisis triggered a severe global economic recession that quickly ended the strong commodity market. Oil prices declined rapidly by year end, with natural gas prices and refined product margins also weakening significantly. The impact of the decline was exacerbated by governmental actions taken earlier in several countries, including increased taxation and unilateral contract abrogation, that were based on mistaken assumptions that strong commodity prices would persist.

ConocoPhillips adapted to these conditions quickly. Early in the fourth quarter, we suspended repurchases of company stock, slowed our capital spending and began taking steps to lower our cost structure.

We support the concerted actions taken by governments worldwide to alleviate the distress in the financial markets and mitigate the economic downturn. Despite these actions, ConocoPhillips considers it possible that the recession could restrain world energy demand and prices for several years.

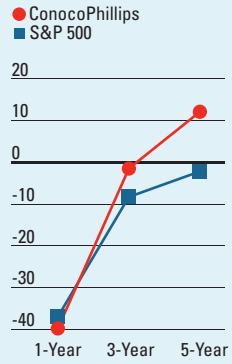
Consistent Strategies and a Strong Asset Portfolio

Although the recession prompted decisive near-term action by ConocoPhillips, it has not altered our long-term strategy. We are a self-sustaining and competitive international, integrated energy company with diligent financial management, strong operating expertise, and an intense focus on maximizing the value of our portfolio.

Through organic growth and prior business transactions, we have assembled the resources and opportunities required for long-term growth. Additionally, the strength of our portfolio gives us confidence in our ability to maintain current levels of production, while fully replacing reserves on an average annual basis over the long term.

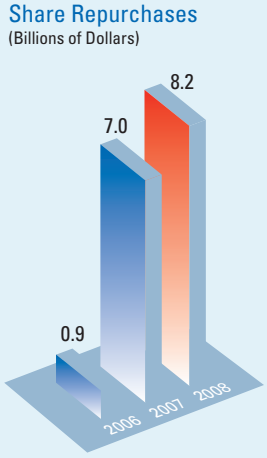
With the 2008 and early 2009 sale of noncore company-owned retail marketing facilities in the United States and Europe, and mature producing properties in several countries, we are nearing completion of our asset rationalization program. We foresee no need for additional substantial asset divestments or acquisitions.

ConocoPhillips has developed plans to permit us to live within our means during 2009 by funding our capital program and dividends from cash flow, thus preserving financial capacity. For 2009, our capital program will total $12.5 billion, a 37 percent reduction from 2008 and well below initially planned levels. As a result, some attractive development projects will be slowed or deferred, but not lost. If economic conditions improve, priority would be given to dividend increases, debt reduction and additional capital spending, with share repurchases considered as conditions warrant.



The company's total shareholder return for 2008 was negative 40 percent, which was comparable to that of the S&P 500 index, but lagged that of our peers – a performance that we believe does not reflect our company's strength and potential.

Over the three-year period ending in 2008, ConocoPhillips repurchased more than 200 million shares of its common stock, valued at more than $16 billion. Share repurchases were suspended during the fourth quarter of 2008 in response to the economic downturn.



A number of developments progressed during 2008. Production startups were achieved in the Yuzhno Khylchuyu (YK) field in Russia, the Alvheim field in Norway, the Qannik field in Alaska, the Su Tu Vang field in Vietnam, the Bohai Bay field in China, and the United Kingdom's Britannia Satellite fields. Production increases were achieved from the Canadian oil sands, and we received government permits for a planned expansion of the Wood River refinery to process this type of oil. In addition, planning and permitting work continued on the proposed Keystone pipeline to transport heavy Canadian crude oil.

We optimized refining performance by achieving strong reliability, while addressing falling gasoline product margins by deferring gasoline-related refining capacity expansions while continuing expansions of distillate capacity.

To drive future growth, a number of major business development initiatives were undertaken. These included formation of a joint venture with Australia's Origin Energy to develop coalbed methane for conversion into liquefied natural gas for export to Asia, an interim agreement with Abu Dhabi to develop the major Shah field's sour natural gas, a Heads of Agreement to lease Kazakhstan's promising N Block in the Caspian Sea, and a Memorandum of Understanding with Brazil's Petrobras to explore possible joint business ventures. Additionally, preparation continued for an open season for the Denali pipeline, which would transport natural gas from Alaska's North Slope.

The retooling of our exploration program continued, with the long-term goals of expanding our acreage inventory,

We are a self-sustaining and competitive international, integrated energy company with diligent financial management, strong operating expertise, and an intense focus on maximizing the value of our portfolio.

increasing exposure to high-potential prospects and ramping up wildcat drilling. We added new acreage in the Gulf of Mexico, Chukchi Sea, Beaufort Sea and numerous onshore basins in North America, and in Indonesia and the North Sea.

ConocoPhillips' strategy continues envisioning diversification into energy production from sources other than oil and natural gas. Near term, however, in today's difficult operating environment, our primary focus remains on our core, traditional upstream and downstream businesses. Development of alternative and renewable energy is proceeding, but at a measured pace.

During 2008, we produced and marketed substantial amounts of renewable fuels, blended ethanol into more than half of our U.S. gasoline output, and facilitated marketing of E-85 and biodiesel fuels at some branded facilities. In conjunction with other companies and academic institutions, we also initiated research on such next-generation renewable fuels as cellulosic ethanol.

Development continued on raw materials for the lithium-ion batteries in electric vehicles, and on the proprietary E-Gas™ coal gasification technology, with a proposed project at a coal mine in Kentucky under consideration. An experimental process to produce methane from natural gas hydrates was tentatively scheduled for testing by the U.S. Department of Energy. Additionally, we continued evaluating opportunities to invest in other forms of energy.

Financial and Operating Highlights

Despite our progress, like the entire industry ConocoPhillips was severely impacted by falling commodity prices, tightening refining margins, and steep declines in share prices. The decline in market capitalization, as well as expectations for extended weakness in prices and margins, necessitated noncash impairments of goodwill related to our Exploration and Production (E&P) business, and to the carrying value of our LUKOIL investment.

These and other impairments in 2008 totaled $34.1 billion. As a result, despite record earnings through three quarters, we closed 2008 with a net loss of $17 billion, or $11.16 per share, compared with a profit during 2007 of $11.9 billion, or $7.22 per share. Our capital program during the year totaled $19.9 billion. Total debt increased to $27.5 billion, compared with $21.7 billion at year-end 2007.

We believe that the impairments are not indicative of the strength of our underlying earnings and cash flow, or the potential offered by our asset base. Exemplifying these attributes, if impairment charges and other similar items are excluded for both years, adjusted earnings during 2008 were $16.4 billion, or $10.66 per share, compared with $15.2 billion, or $9.21 per share, in 2007.

ConocoPhillips performed strongly from an operational standpoint. Safety performance improved as both employees and contractors recorded significantly fewer incidents, but several contractor deaths occurred. Environmental performance featured reductions in produced water spills and flaring volumes, but an increase in hydrocarbon spills. We are determined to further enhance our operational reliability and performance in the vital areas of health, safety and environmental stewardship.

Production volumes met expectations, excluding impacts from higher commodity prices on production sharing contracts, and weather-related shutdowns. The upstream business produced 2.2 million barrels of oil equivalent per day (BOED), including volumes from E&P and net production of 0.4 million BOED from our LUKOIL investment. Excluding the impact of Dec. 31, 2008, prices, the company's organic reserve replacement ratio totaled 84 percent. However, due to downward reserve revisions to adjust to the low year-end commodity prices, our overall reserve replacement rate was 31 percent. ConocoPhillips ended the year with total reserves of 10.0 billion barrels of oil equivalent.

Refining and Marketing achieved high operating reliability at our U.S. refineries, although hurricanes temporarily closed three facilities and reduced volumes elsewhere. Our U.S. refining crude oil capacity utilization rate of 92 percent exceeded the industry average for the seventh consecutive year, and the combined U.S. and international utilization rate was 90 percent.

Our adjusted return on capital employed improved, and E&P outperformed its peer group in cash generated per barrel of oil equivalent.

The global economic conditions and near-term energy environment are more challenging than we have seen for decades.

However, the performance of ConocoPhillips stock was disappointing. After setting share price records in mid-2008, its subsequent decline caused a negative 40 percent shareholder return for the year. The year's return was comparable to that of the Standard & Poor's (S&P) 500 index, but lagged that of our peers – a performance that we believe does not reflect our company's potential. Even with the 2008 results, over the past five years ConocoPhillips shareholders have realized an average return exceeding 12 percent annually, compared with a 9 percent average for our peers and a 2 percent annual average decline in the S&P 500 index.

During 2008, we increased our dividend by 15 percent, the seventh consecutive year of increases, and repurchased $8.2 billion in company shares, concluding $15.2 billion in repurchases over the past two years. We remain committed to enhancing shareholder value.

Corporate Citizenship

ConocoPhillips is determined to meet the highest legal and ethical standards, and to practice sound environmental stewardship and good corporate citizenship. We believe in sustainable development, which we define as operating in a manner that promotes ongoing economic growth, a healthy environment, and vibrant communities.

We strive to improve the well-being of the communities in which we operate by making contributions that help support vital community services. During 2008, our philanthropic investments totaled $70 million for education and youth services, health and social services, civic and arts initiatives, environmental and industrial safety programs, and emergency relief.

Key contributions were made for disaster relief in communities impacted by the three hurricanes that struck the U.S. Gulf Coast during the year.

Working with Government

As a U.S.-based company, we anticipate a broad range of governmental energy initiatives to emerge as a result of the new administration in Washington, D.C. We continue urging enactment of a comprehensive national energy policy. This policy should expand industry access to the nation's abundant undeveloped oil and natural gas resources, while encouraging greater energy efficiency, innovation and environmental care. It also should ease the regulatory and permitting hurdles that currently impede energy infrastructure construction.

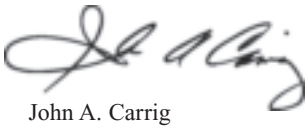
Further, we continue calling for passage of a climate change policy that establishes a mandatory national framework to address greenhouse gas emissions. Such a policy has been proposed by the U.S. Climate Action Partnership, of which ConocoPhillips is a member.

Even as we position our company to withstand today's recession, we believe that the national and global economies will recover in time, that growth in energy demand will resume, and that oil and natural gas will remain society's primary energy sources far into the future.

The global economic conditions and near-term energy environment are more challenging than we have seen for decades. Yet we are convinced that ConocoPhillips is pursuing the right strategies for long-term success.

As we manage the global challenges that confront our industry, the commitment and involvement of ConocoPhillips employees will be essential. They contributed immeasurably to our progress in the past, and will help lead the way to the future. We sincerely appreciate their efforts, as well as the support of our shareholders.

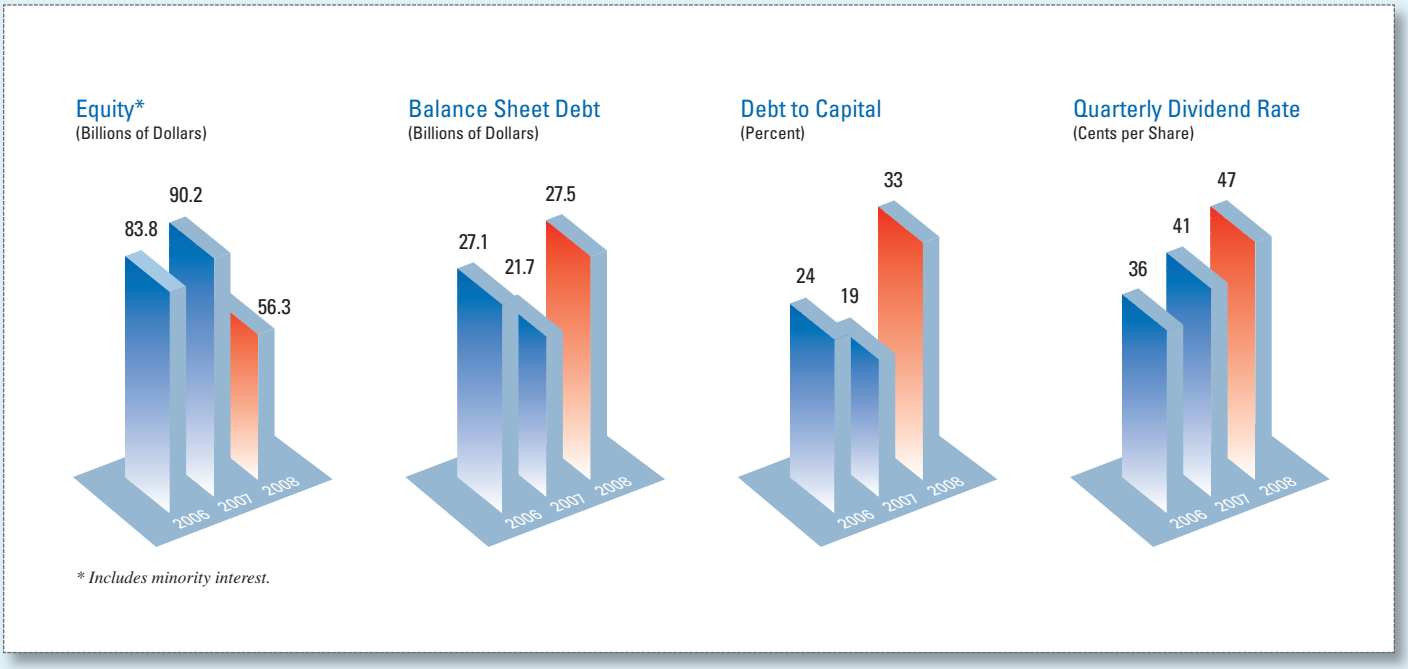
James J. Mulva
Chairman and Chief Executive Officer



John A. Carrig
President and Chief Operating Officer
March 1, 2009

Financial Review

Adapting to Market Conditions



** Includes minority interest.*

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

ConocoPhillips applies a proven investment strategy that allocates capital in a balanced manner to achieve growth, enhance shareholder returns, and manage debt.

"We can manage through economic downturns while still funding opportunities that will benefit shareholders over the long term," says Sig Cornelius, senior vice president, Finance, and chief financial officer. "Despite the world banking and financial crisis, ConocoPhillips enjoys favorable access to capital due to our strong balance sheet and solid investment-grade credit rating. Our plans are designed to enable us to adapt to the currently unfavorable market conditions while prudently managing our debt."

2008 Financial Results

ConocoPhillips had a net loss of $17 billion during 2008, or $11.16 per share, compared with a profit of $11.9 billion, or $7.22 per share, in 2007. The loss was due to fourth-quarter noncash impairments necessitated by substantial declines in energy prices and equity markets late in the year. Approximately $25.4 billion of the impairments was related to goodwill in our Exploration and Production (E&P) business; the carrying value of our LUKOIL investment was reduced by $7.4 billion; and other asset impairments totaled $1.3 billion after-tax.

"These noncash charges did not impact the strategic value of our assets, or our ongoing ability to generate substantial cash flow from operations," says Cornelius. "They were necessitated by the unique market events during the fourth quarter of 2008."

Excluding these charges and other similar items, the company's adjusted earnings during 2008 were $16.4 billion, or $10.66 per share.

Overall, the company's performance was comparable with that of its industry peers on key per-share and per-barrel metrics.

Debt Management

Total debt was $27.5 billion at year-end 2008, a $5.8 billion increase from the year before. ConocoPhillips generated $24.3 billion in cash flow from operations and asset sales; spent $19.9 billion in its capital program, including an investment in a new coalbed methane and liquefied natural gas venture with Origin Energy in Australia; and distributed $11.1 billion to shareholders through dividends and share repurchases.

ConocoPhillips ended the year with a debt-to-capital ratio of 33 percent, reflecting the impact of the fourth-quarter impairments and the debt increase, compared with its 20 percent to 25 percent target range.

"We are committed to maintaining financial flexibility through careful management of the balance sheet," says Cornelius. "Our debt-ratio target remains unchanged."

Stockholders' equity and minority interests at year-end 2008 were $56.3 billion, compared with $90.2 billion at year-end 2007.

Dividends and Share Repurchases

ConocoPhillips increased quarterly dividends on its common stock by 15 percent during 2008 to 47 cents per share, the seventh consecutive annual increase since the company's formation in 2002. The company also expended $8.2 billion on share repurchases, reducing total shares outstanding to 1,480 million at year end.

"Future dividend increases, debt reduction, additional capital spending and share repurchases will be considered as conditions warrant," says Cornelius.

Capital Program

The company's capital program during 2008 totaled $19.9 billion, compared with $12.9 billion in 2007. The increase was attributable to the Australian investment and expanded drilling and development opportunities.

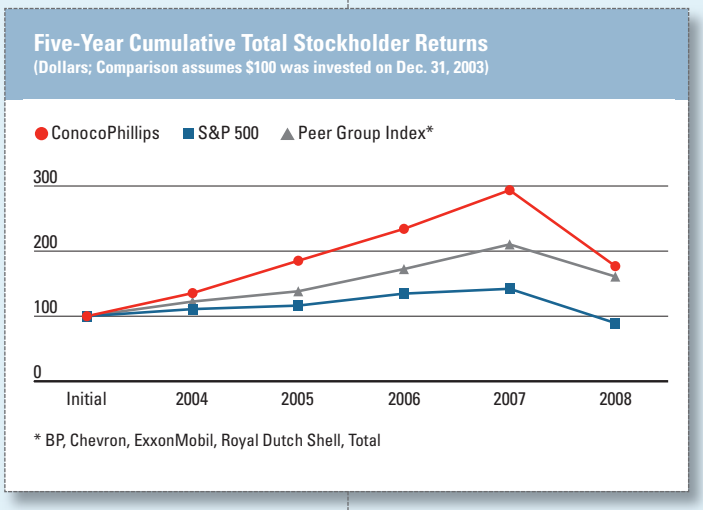
The planned 2009 capital program totals $12.5 billion, including capitalized interest. Loans to affiliates and contributions to fund the EnCana venture are expected to total $0.8 billion, and capital expenditures are expected to total $11.7 billion.

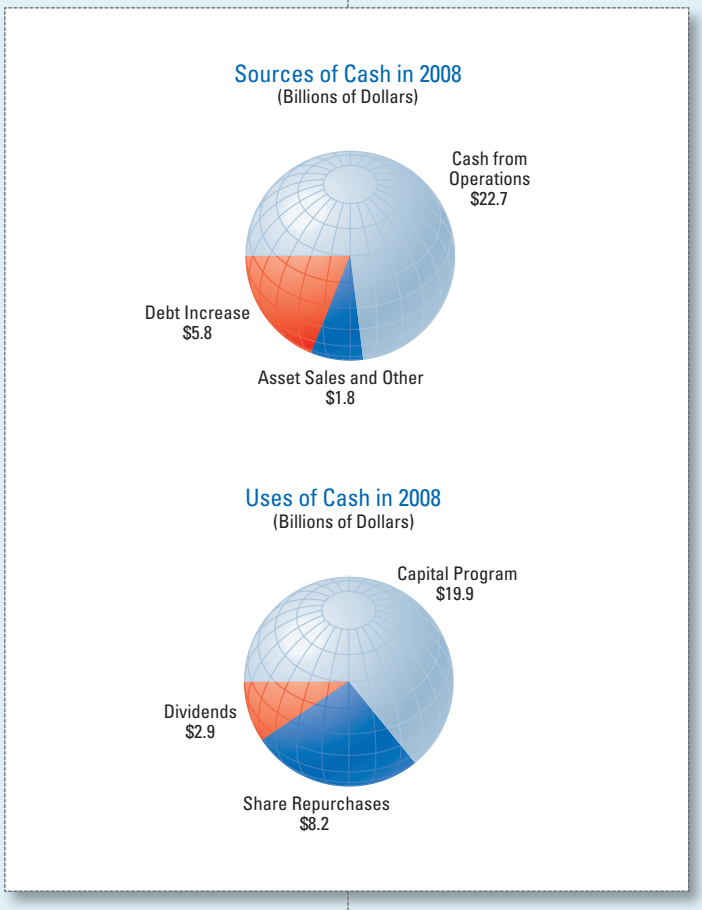
"We have budgeted prudently in response to the current market," says Cornelius. "Our existing portfolio allows us the flexibility to adjust to changing market conditions while also advancing the company's strategic investments."

Approximately $10.3 billion, or 82 percent of the company's total capital program, will fund ongoing E&P drilling and development programs in the United States, Canada, the North Sea, the Asia Pacific region, the Middle East, Russia and the Caspian Sea. Of this, $1.4 billion will be allocated to exploration.

Refining and Marketing will receive $2 billion in capital, or 16 percent of the total program, for investments to enhance safety, regulatory compliance and reliability, and increase conversion capability, clean-product yields and transportation capacity. Plans for the Wilhelmshaven refinery upgrading project are progressing. Other projects, including the proposed Yanbu refinery venture in Saudi Arabia, have been slowed or deferred as warranted.

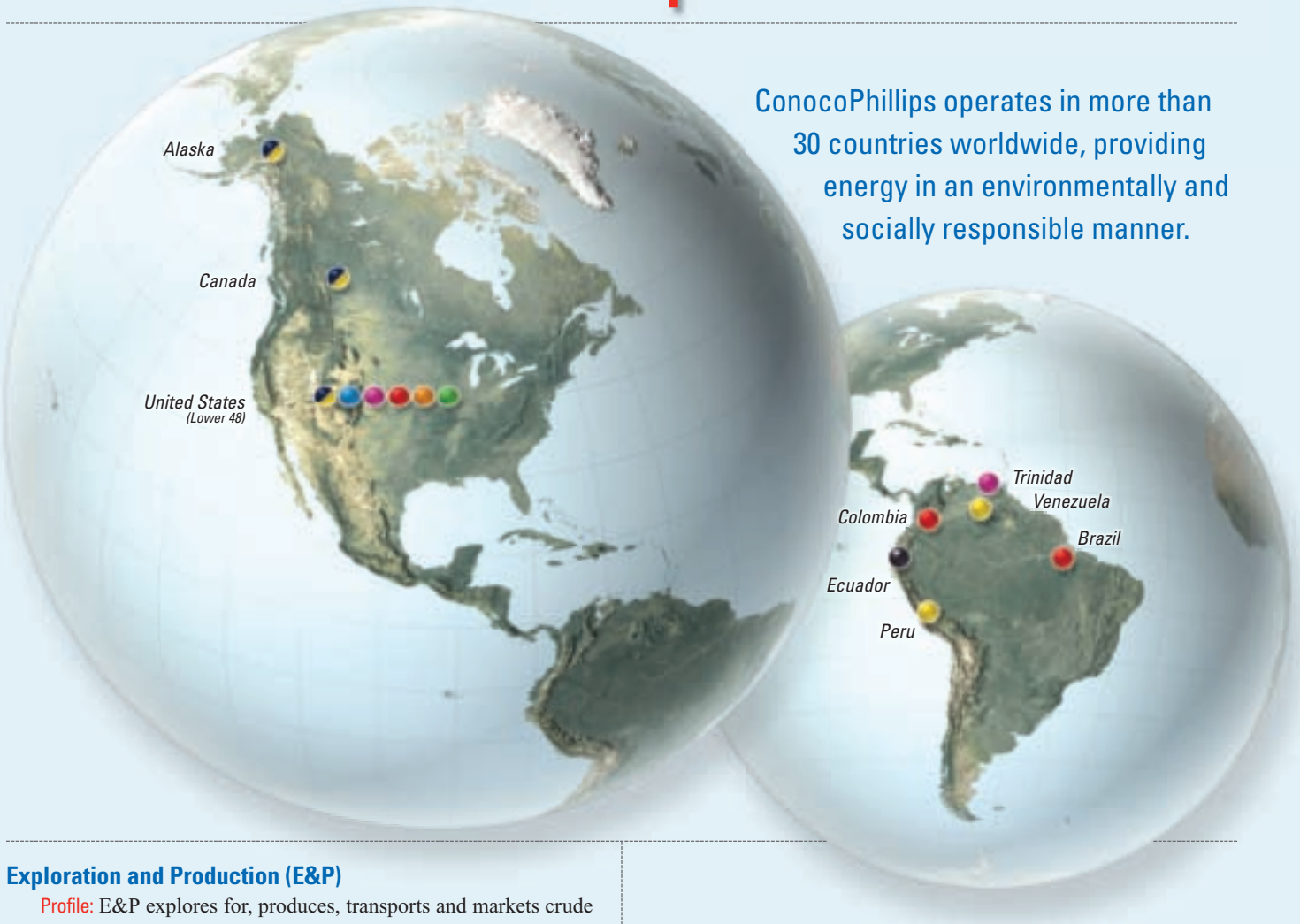
Approximately $0.2 billion in capital is allocated to Corporate and Emerging Businesses, with the majority planned to enable the 2009 completion of the Immingham Combined Heat and Power expansion project.





We can manage through economic downturns while still funding opportunities that will benefit shareholders over the long term.

Worldwide Operations



ConocoPhillips operates in more than 30 countries worldwide, providing energy in an environmentally and socially responsible manner.

Exploration and Production (E&P)

Profile: E&P explores for, produces, transports and markets crude oil, natural gas, natural gas liquids (NGL) and liquefied natural gas (LNG) worldwide. Key focus areas include developing legacy assets – large producing projects that provide strong long-term financial returns – and exploring for new reserves in promising areas. E&P also extracts bitumen from Canada's oil sands and upgrades it into synthetic crude oil.

Operations: At year-end 2008, E&P held a combined 72 million net developed and undeveloped acres in 21 countries and produced hydrocarbons in 14, with proved reserves in three additional countries. Crude oil production in 2008 averaged 806,000 barrels per day (BD), natural gas production averaged 4.85 billion cubic feet per day (BCFD), and NGL production averaged 153,000 BD.

Refining and Marketing (R&M)

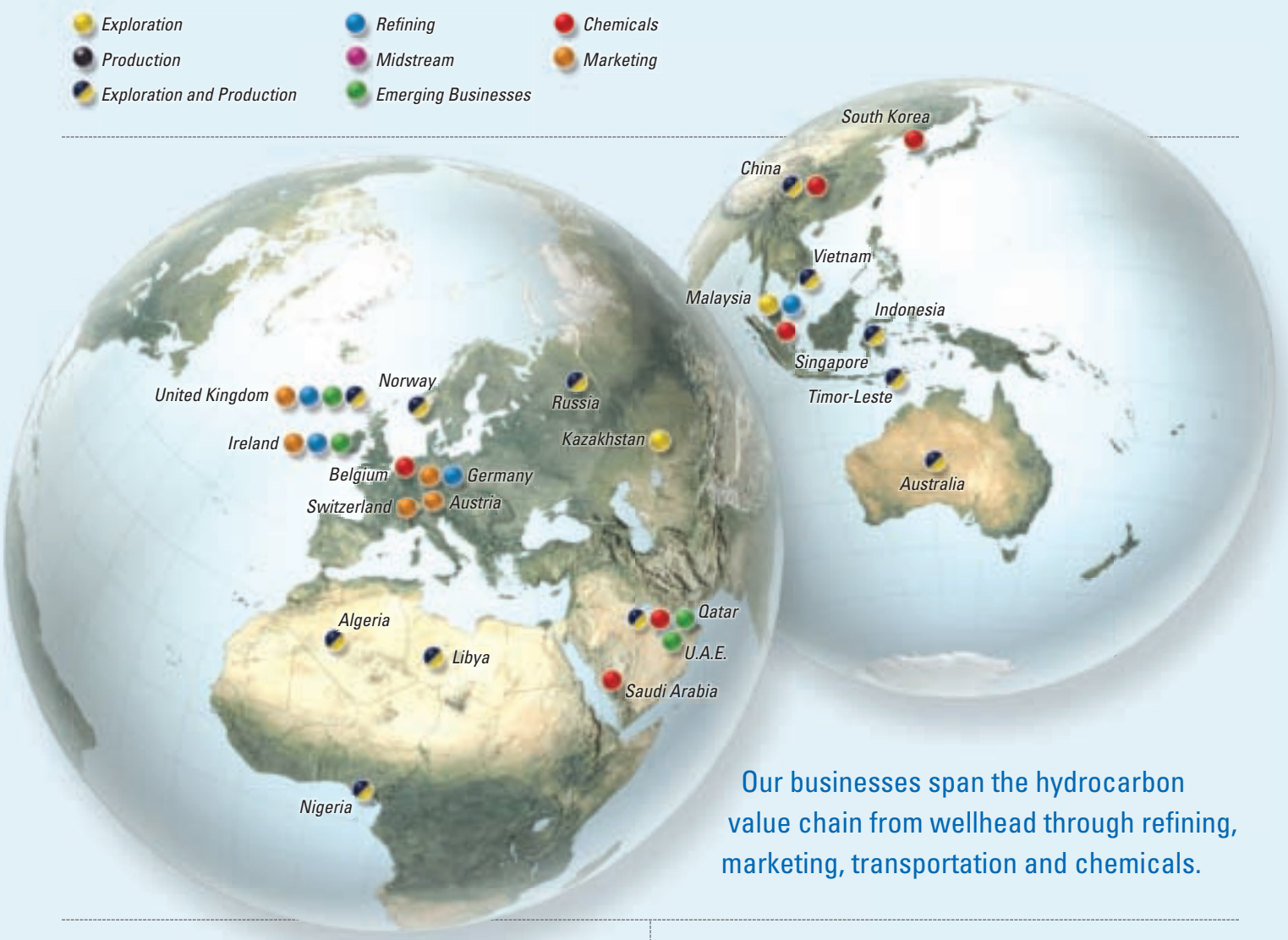
Profile: R&M refines crude oil and other feedstocks into petroleum products and markets and transports them. Based on crude oil capacity, ConocoPhillips is the world's fourth-largest refiner and the second-largest U.S. refiner.

Operations: R&M has operations in the United States, Europe and the Asia Pacific region. *Refining* – At year-end 2008, R&M owned interests in 12 U.S. refineries, with aggregate net crude oil processing capacity of 2,008,000 BD. It also owned interests in five refineries outside the United States, with aggregate net crude oil processing capacity of 670,000 BD. *Marketing* – At year-end 2008, R&M sold gasoline, distillates and aviation fuel through approximately 9,800 outlets in the United States and Europe. In the United States, products were marketed primarily under the Conoco®, Phillips 66® and 76® brands and in Europe primarily under the JET® brand. R&M also sold and marketed lubricants, commercial fuels and liquid petroleum gas. Additionally, the company participated in the specialty products business directly and through joint ventures. Refined products sales totaled 3.0 million BD in 2008. *Transportation* – At year-end 2008, R&M held interests in approximately 28,000 miles of U.S. pipeline systems, including those partially owned or operated by affiliates.

LUKOIL Investment

Profile: ConocoPhillips has a 20 percent ownership in LUKOIL, an international, integrated oil and natural gas company headquartered in Russia.

Operations: At year-end 2008, LUKOIL had exploration, production, refining and marketing operations in about 30 countries. During 2008, ConocoPhillips' estimated share of LUKOIL's production was 445,000 barrels of oil equivalent per day and refining crude oil throughput was 229,000 BD.



Our businesses span the hydrocarbon value chain from wellhead through refining, marketing, transportation and chemicals.

Midstream

Profile: ConocoPhillips' Midstream segment consists of a 50 percent interest in DCP Midstream, LLC and certain ConocoPhillips assets located predominantly in the United States. Midstream gathers natural gas, processes it to extract NGL, and sells remaining residue gas to electrical utilities, industrial users and marketing companies.

Operations: At year-end 2008, DCP Midstream had approximately 60,000 miles of pipelines and owned or operated 53 NGL extraction and 10 fractionation plants. Its raw natural gas throughput averaged 6.2 BCFD, and NGL extraction averaged 360,000 BD.

Chemicals

Profile: ConocoPhillips has 50 percent ownership of Chevron Phillips Chemical Company LLC (CPChem), a joint venture with Chevron Corporation. The company produces olefins and polyolefins, including ethylene, polyethylene and other olefin products; aromatics and styrenics, including styrene, benzene, cyclohexane and paraxylene; and specialty products, including chemicals, catalysts and high-performance polymers and compounds.

Operations: At year-end 2008, CPChem had 15 facilities located in the United States and nine polyethylene pipe, conduit and pipe fittings plants. Major international production facilities were in Belgium, China, Saudi Arabia, Singapore, South Korea, Colombia, Brazil and Qatar.

Emerging Businesses

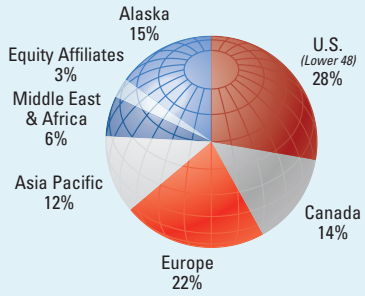
Profile: Emerging Businesses develops new businesses and technology complementary to traditional operations. These efforts include development of integrated power generation projects to support E&P and R&M strategies and business objectives; carbons-to-liquids processes that convert carbon into a wide range of transportable products; and a variety of technology solutions.

Operations: During 2008, ConocoPhillips progressed toward the planned completion in 2009 of an expansion of the Immingham Combined Heat and Power facility located near the United Kingdom's Humber refinery. The expansion will make this one of the world's largest and most efficient cogeneration facilities. Also, the company entered collaborations to develop renewable transportation fuels from biomass such as nonfood crops, wood or switchgrass, and from other sources, including algae.

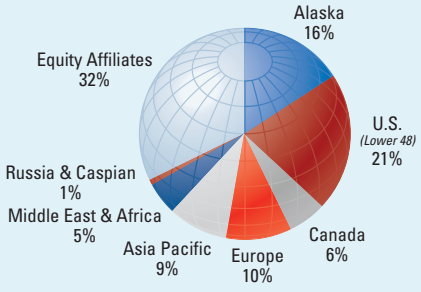
Key focus areas include developing legacy assets and exploring for new reserves in promising areas.

Operating Review

2008 E&P Production



2008 Worldwide Reserves



ConocoPhillips initiated oil production from Vietnam's Su Tu Vang field ahead of schedule, a noteworthy achievement during an era of high industry activity that strained availability of equipment and supplies.

Exploration and Production

Maintaining Volumes and Pursuing Long-Term Growth

During 2008, ConocoPhillips' Exploration and Production (E&P) business continued developing its core producing areas, executing major growth projects and capturing large-scale strategic opportunities.

"Our existing asset base offers ongoing potential to increase resource recovery, extend field life and maximize profitability," says Jim Gallogly, executive vice president, Exploration and Production. "Throughout the year, we maintained an intense pace on dozens of ongoing major field development programs and projects around the world, and achieved new production from several key startups. The size and depth of our opportunity portfolio reinforces our commitment to creating long-term shareholder value.

"The foundation of our success and the most important priority of our business remains operating safely and in an environmentally and socially responsible manner," Gallogly adds. "Our total recordable incident rate declined more than 10 percent in 2008, following significant improvements the year before. We are committed to further enhancing both employee and contractor safety as we progress toward our goal of an incident-free workplace."

During the year's first three quarters, E&P benefited from favorable crude oil and natural gas prices, but production was impacted by the unplanned shutdown of another firm's natural gas processing facility in New Mexico's San Juan Basin, and by weather-related impacts across the United States. Volumes increased during the final quarter, due primarily to project startups. Commodity prices declined significantly late in the year.

In 2008, E&P delivered production (including Syncrude) of 1.79 million barrels of oil equivalent per day (BOED), down 5 percent from 2007. The organic reserve replacement ratio was 84 percent, excluding the impact of low year-end prices. The overall reserve replacement ratio was 31 percent, including year-end price impacts, sales and purchases. Proved reserves (excluding Syncrude) at year-end 2008 totaled 10.0 billion BOE, including negative revisions of 0.5 billion BOE from the impact of low year-end prices used to calculate reserve volumes. Capital program funding was $12.5 billion, excluding $4.7 billion associated with a new venture with Origin Energy in Australia. The capital program budget for 2009 is $10.3 billion, with the reduction a response to the current difficult business environment. Several nonstrategic assets were sold during 2008.

James L. Gallogly
Executive Vice President, Exploration and Production

Continued Investment in Base Assets

E&P's extensive producing assets in the U.S. Lower 48, Canada, Alaska and the North Sea have long been part of the company's foundation.

In the Lower 48, ConocoPhillips was the largest onshore oil, natural gas liquids and natural gas producer with approximately 475,000 BOED produced in 2008. The company's substantial ongoing investments are yielding new opportunities to enhance its portfolio and maintain leadership in many of the region's key producing basins. During 2008, E&P built significant acreage positions in several promising new resource plays. Significant progress also was made on the 1,679-mile Colorado-to-Ohio Rockies Express Pipeline, which upon completion is expected to improve prices received for Rockies-area natural gas production.

Startups occurred on two key North Sea projects, the Britannia Satellites (BritSats) and Alvheim. The new BritSats volumes raised total Greater Britannia net production to 70,000 BOED, while Alvheim's volumes brought total partner-operated net production in the North Sea to 130,000 BOED. Exploitation of the Greater Ekofisk Area continued, and plans are progressing for significant additional development and extension of this legacy asset.

Canada's substantial natural gas producing properties achieved improved operational efficiency and uptime, and E&P's production there exceeded expectations. Promising new acreage was added in the Muskwa and Montney shale gas trends in British Columbia. ConocoPhillips expects to continue making substantial investments in western Canada's prolific natural gas producing areas. The Surmont oil sands

2008 Major Accomplishments

- Met production expectations, excluding storm disruptions and price impacts on production sharing contracts.
- Achieved startups in Norway, Alaska, Vietnam, China and the United Kingdom.
- Reached agreement to develop coalbed methane in Australia and sour natural gas in Abu Dhabi; negotiated Heads of Agreement on exploratory block in Kazakhstan; and formed Denali natural gas pipeline venture in Alaska.
- Added onshore and offshore exploratory acreage in North America, Indonesia and the North Sea.

Exploration and Production Financial and Operating Results

	2008	2007
Net income (loss) (MM)	**$ (13,479)**	$ 4,615
Adjusted earnings (MM)	**$ 12,072**	$ 8,483
Proved reserves[1] (BBOE)	**10.0**	10.6
E&P worldwide production[2] (MBOED)	**1,789**	1,880
E&P crude oil production (MBD)	**806**	854
E&P natural gas production (MMCFD)	**4,847**	5,087
E&P realized crude oil price ($/BBL)	**$ 93.12**	$ 67.11
E&P realized natural gas price ($/MCF)	**$ 8.27**	$ 6.26

[1] Includes LUKOIL.
[2] Includes Syncrude.

Ryan M. Lance
President, Exploration and Production – Europe, Asia, Africa and the Middle East

The Alpine field in Alaska remains a focus of step-out drilling activity as ConocoPhillips utilizes its extensive Arctic operational experience and expertise.

operation in northern Alberta completed its first year of bitumen production, exceeding projections. E&P also completed its largest oil sands delineation program to date, drilling more than 400 gross wells, one-third of which were company operated. In the Canadian Arctic, where E&P has a premier resource-ownership position, work continues to progress the proposed Mackenzie Delta natural gas pipeline and the company-operated Parsons Lake upstream development.

In Alaska's large Prudhoe Bay and Kuparuk Areas, E&P is utilizing exploitation, good field management and enhanced oil recovery to maintain production from legacy oil fields. Development of the Western North Slope continued with the startup of Qannik, the third Alpine satellite field. Additionally, ConocoPhillips and BP formed the Denali joint venture to develop a pipeline to transport 4 billion cubic feet per day (BCFD) of currently stranded natural gas to the U.S. Lower 48. The venture plans to conduct an open season for pipeline capacity beginning in 2010.

Developing New Growth Regions

While core operations in North America and the North Sea represent a solid and stable foundation of production, progress also was achieved on major projects in international growth regions – the Russia and Caspian, Middle East and Asia Pacific areas.

First production was achieved from the Yuzhno Khylchuyu (YK) field in northern Russia, part of the Naryanmarneftegaz joint venture with LUKOIL, with net production at year end of 24,000 BOED. Planned phase II activities would increase net production to 45,000 BOED in 2009.

In the Caspian Sea region, construction continued on the Kashagan field phase I development and approval was given to start engineering and design for phase II. The project's co-venturers reached final agreement with Kazakhstan's government on its development costs and schedule, and on increasing the national oil company's ownership. As a result, ConocoPhillips' ownership decreased from 9.26 percent to 8.4 percent. Estimated net peak production of 130,000 BOED is anticipated upon full field development.

In the Middle East, preparation continued for the 2010 startup of the Qatargas 3 liquefied natural gas (LNG) facility in Qatar. Key achievements included completion of topsides facilities for three platforms and launching of vessel hulls for 10 LNG tankers. Peak net production of an expected 80,000 BOED would continue during a 25-year plateau.

In the Asia Pacific region, early production from China's Bohai Bay phase II project was achieved, with full field startup anticipated during 2009 and net peak production of 70,000 BOED expected in 2010. Progress was achieved on several other projects, including first production from the Su Tu Vang oil field offshore Vietnam; and in Indonesia, installation of North Belut C and D wellhead platforms and ramp-up of the Kerisi field, which is performing above expectations. In Malaysia, the Gumusut project is well under way, with engineering proceeding for the neighboring Kebabangan and Malikai projects. Collectively, the three offshore projects are expected to yield peak net production of 80,000 BOED in 2014 and establish Malaysia as an important part of the company's Asia Pacific portfolio.

New Opportunities for Long-Term Growth

E&P had several major exploration and business development successes during 2008.

Successful lease sale participation added 22 new deepwater blocks in the U.S. Gulf of Mexico and 98 blocks in the Chukchi Sea in Alaska, the first lease sale in this area since 1988. New leases also were awarded in the Canadian Beaufort Sea, the Indonesian Arafura Sea and the North Sea. Further, the company successfully negotiated a Heads of Agreement for a 24.5 percent interest in Kazakhstan's N Block in the Caspian Sea, the site of several promising exploration prospects.

In Abu Dhabi, ConocoPhillips signed an interim agreement to develop the world-scale Shah field's sour natural gas. The project will involve constructing a 1 BCFD processing plant, new natural gas and liquids pipelines and sulfur-exporting facilities. ConocoPhillips will have a 40 percent interest.

Additionally, ConocoPhillips and Origin Energy announced plans to create a long-term natural gas business focused on coalbed methane production in Australia and the processing and export sale of LNG.

"We view the Origin venture as an opportunity to duplicate the success of our 50-year presence in the San Juan Basin. We are the leading producer of coalbed methane there, and have gained expertise we can now utilize with our LNG experience to build a new business focused on the Asian energy markets," says Ryan Lance, president, E&P – Europe, Asia, Africa and the Middle East.

Well Positioned for Continued Success

As E&P moves into 2009, it faces a challenging operating environment characterized by weak commodity prices. However, ConocoPhillips takes a disciplined, long-term view of its upstream business, one that extends beyond short-term trends.

"We will continue investing to grow production and develop the reserves that society will need tomorrow. We will emphasize operating excellence, which we define as safe, environmentally sound and reliable operations. We are also working to reduce our costs," Gallogly says. "With a robust core of stable assets, coupled with a strong portfolio of near-term growth projects and long-term opportunities, we are determined to compete effectively and move beyond the current downturn to continue our long-term growth."

Refining and Marketing

Operating Profitably in a Challenging Environment

A weakened global economy and declining gasoline demand contributed to lower refining margins and financial results for ConocoPhillips' Refining and Marketing (R&M) business in 2008, compared with its record-breaking performance in 2007.

R&M still achieved significant operating earnings by increasing yields of higher-valued refined products and outpacing industry refinery utilization rates. Additionally, R&M further improved safety performance and made progress on key environmental initiatives.

Looking ahead, R&M will strive to reduce costs and optimize profitability in a difficult economy, while continuing to improve safety and environmental performance. Also, R&M deferred some discretionary projects and will conserve capital in order to help ConocoPhillips maintain financial flexibility.

"Though the economy has impacted the timing of our growth plans, we are consistently pursuing our proven strategies," says Willie Chiang, senior vice president, Refining, Marketing and Transportation. "We expect to remain competitive by maintaining our focus on operating excellence, cost control, margin enhancement, and good portfolio management."

Expansion of the Wood River refinery in Illinois will facilitate processing of crude oil from the company's Canadian oil sands projects, which represent major future potential for ConocoPhillips.

W.C.W. Chiang
Senior Vice President, Refining, Marketing and Transportation

2008 Major Accomplishments

- Achieved high operating reliability and safety.
- Recorded 92 percent U.S. refining crude oil capacity utilization, exceeding industry average for seventh consecutive year.
- Adjusted to tight refining margins by shifting emphasis to distillate fuels and conserving capital.

Refining and Marketing Financial and Operating Results

	2008	2007
Net income (MM)	**$ 2,322**	$ 5,923
Adjusted earnings (MM)	**$ 2,672**	$ 5,331
Crude oil capacity utilization	**90%**	94%
Clean product yield	**81%**	80%
Petroleum product sales (MBD)	**3,040**	3,245

Improving Safety and Reliability

Operating excellence is the cornerstone of R&M's strategy, incorporating safe and reliable operations, environmental stewardship and corporate citizenship. Safety leadership training and an increased emphasis on accountability led to a 17 percent improvement in employee and contractor safety in 2008, compared with 2007, R&M's best-ever performance.

ConocoPhillips volunteers helped plant 70,000 trees and shrubs at Mayflower Wood, a 120-acre nursery woodland near the Humber refinery in the United Kingdom.

"Emphasizing employee and supervisor accountability has resulted in a renewed commitment to work safely and address potential hazards before work begins," says Chiang.

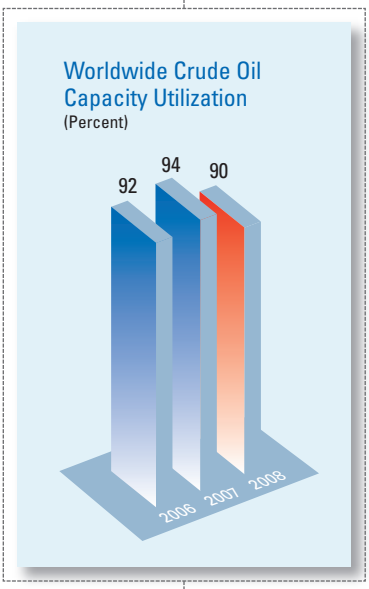
Process safety remains a key focus area, and the results of safety audits performed in 2008 will be used to drive improvements in 2009 and beyond.

Several facilities received external recognition for exemplary safety performance. The Sweeny, Texas, refinery, the Wood River joint venture refinery in Roxana, Ill., and lubricants plants in Lake Charles, La., and Savannah, Ga., all earned STAR status under the U.S. Occupational Safety and Health Administration's Voluntary Protection Program. Additionally, the Billings, Mont., refinery received the Governor's Cup for Excellence in Workplace Safety and Health, the state's highest safety honor.

ConocoPhillips is committed to reducing its environmental footprint. R&M actively measures and forecasts its refinery emissions to ensure regulatory compliance and identify opportunities for equipment upgrades. For example, a wet gas scrubber and other equipment installed at the Los Angeles, Calif., refinery in 2008 capture most particulates from the cracking process, lowering particulate emissions by 75 percent. Ongoing energy-efficiency improvements also help reduce emissions.

R&M has assessed water use at its refineries and identified several conservation opportunities. An upgraded cooling tower control system reduced the Lake Charles, La., refinery's water usage by 50 million gallons per year.

An active U.S. hurricane season temporarily shut down three refineries and reduced runs elsewhere. Despite these impacts, high operating reliability led to a U.S. refining crude oil capacity utilization rate of 92 percent, exceeding the industry average for the seventh consecutive year, and a combined U.S. and international utilization rate of 90 percent.



ConocoPhillips has improved reliability through infrastructure modernization, personnel training and key debottlenecking projects across its refining system. One recent debottlenecking project at the Los Angeles, Calif., refinery improved reliability and increased liquids yields from the coker unit.

In recognition that community support is vital, most of the company's U.S. refineries have community advisory panels to facilitate dialogue between management and local citizens. R&M also supports numerous community projects. Volunteers from the Humber refinery in the United Kingdom helped plant nearly 70,000 trees and shrubs at Mayflower Wood, a 120-acre nursery woodland. In Louisiana, ConocoPhillips is supporting construction of five community centers in the hurricane-ravaged area surrounding the Alliance refinery south of New Orleans.

Enhancing Margins and Controlling Costs

As global gasoline demand declined during 2008, R&M quickly optimized its operations to increase yields of distillates, which were in strong demand and offered higher margins than other products.

"This 'dieselization' of our refineries has been successful," says Chiang. "Having the flexibility to increase yields of higher-margin products is an advantage."

Optimization of feedstock supply is another key to margin enhancement. Investments to enhance capacity to process cost-advantaged crude oil continue. The newest coker at the Borger, Texas, joint venture refinery accommodates cost-advantaged sour crude oil from Canada. In Europe, the company's refineries processed several new types of crude oil during 2008.

R&M also continues investing in opportunities to increase clean-fuels production and incorporate biofuels and renewable fuels into the product mix. A new hydrocracker at the Rodeo, Calif., refinery scheduled to start up in 2009 will raise output of ultra-low-sulfur diesel fuel and low-sulfur gasoline by 13 percent, while improving energy efficiency. Future projects will reduce levels of benzene in gasoline to meet required standards.

Renewable diesel fuel can be produced at refineries in Borger, Texas, and Ireland. Additionally, most U.S. product storage terminals have been upgraded to blend ethanol, and several have been upgraded to distribute biodiesel. For its leadership in biofuels utilization and research, ConocoPhillips recently was recognized as Refining and Energy Company of the Year by a prominent industry publication.

R&M's cost-management strategy is focused on improving operating excellence, eliminating defects and employing new technologies, while offsetting inflation through strategic sourcing. For example, the use of new assessment tools reduced pipeline

Through training drills and a relentless focus on safety, Refining and Marketing employees and contractors improved their safety performance by 17 percent during 2008.

inspection costs 20 percent, while maintaining rigorous standards. Since 2006, U.S. refining base expenditures per barrel for personnel, maintenance, turnarounds, catalyst, chemicals, and contract costs have been flat on an inflation-adjusted basis. Similarly, the remaining U.S. and European marketing businesses achieved a 4 percent reduction per barrel sold through strategic portfolio changes, reducing overhead and employing new technology.

Although energy prices have declined from their mid-2008 peak, energy consumption remains a major operating cost. Small capital investments and refinery optimization programs are leading to significant savings. When adjusted for commodity price changes, energy usage per barrel has fallen more than 3 percent since 2006 at R&M's U.S. refineries.

A Flexible Strategy for Growth and Profitability

In order to improve the profitability of its asset portfolio, in recent years R&M has divested assets not geographically integrated with refining operations, strategically shifted marketing to a wholesale model, upgraded underperforming assets, and completed transactions that improve integration with ConocoPhillips' upstream business.

During 2008, R&M realized more than $550 million from the sale of U.S. and European assets, including the Nordic retail network, certain U.S. transportation assets, and the Penreco specialty business. The sale of a large portion of R&M's U.S. retail marketing assets closed in January 2009, with disposition of the remainder expected during 2009. These dispositions allow R&M to focus on integrating refinery output with a lower-cost network of strong branded wholesalers.

Several key strategic investments are under way to increase clean-product yield, enhance crude processing flexibility and improve upstream integration. However, the investment pace has been slowed due to the weak global economy. Resulting delays are expected to yield savings as costs for labor and materials decline.

Bidding associated with planned construction of the 400,000-barrel-per-day (BD) Yanbu export refinery in Saudi Arabia has been deferred. Also deferred are a planned coker at the Ferndale, Wash., refinery, and installation of a new crude and vacuum unit at the Billings, Mont., refinery.

During 2008, ConocoPhillips initiated a process to reduce its planned ownership in the Keystone pipeline from 50 percent to 20 percent by late 2009. The pipeline will carry crude oil from Canada to the United States, further leveraging ConocoPhillips' upstream position in Canada. An extension announced in 2008 will provide another source of cost-advantaged crude oil to R&M's refineries located on the U.S. Gulf Coast.

Governmental permits were secured in 2008 to allow advancement of a coker project and expansion of the Wood River refinery, part of the WRB business venture with EnCana. The project will more than double capacity to process bitumen-based and other advantaged crude oils produced in Canada, while increasing overall capacity and clean-product yields.

Other current projects include a 20,000 BD hydrocracker complex nearing completion at the Rodeo, Calif., refinery. The hydrocracker employs technology that enables shifts in production between gasoline and diesel depending on market conditions. In addition, an expansion of the Melaka joint venture refinery in Malaysia will, when completed in 2010, increase net processing capacity by 20,000 BD.

In Germany, work continues on the upgrading of the Wilhelmshaven refinery to enable it to process heavier, higher-sulfur crude oil and produce predominantly low-sulfur diesel fuel.

"We are committed to further improving the safety, reliability and environmental performance of our operations, and will continue to invest in these areas," says Chiang. "A number of discretionary high-return, strategic projects will enable R&M to adapt to changing economic conditions. Most importantly, we rely on our diverse and talented organization of 12,000-plus people, spread among offices, refineries, pipelines, terminals, marketing and headquarters, to help deliver these results."

ConocoPhillips markets gasoline, distillates and aviation fuel products in the United States primarily under the Conoco®, Phillips 66® and 76® brands. In Europe, it markets its products primarily through the JET® brand.

Commercial

Finding Growth Opportunities in a Changing Market

The ConocoPhillips Commercial organization maintained supply reliability while adding long-term value in 2008 by expanding existing businesses; increasing strategic trading, storage and transport capacity; and entering new markets.

With offices in Houston, London, Calgary, Singapore and Dubai, Commercial is well positioned to pursue global opportunities. The group manages the company's worldwide product portfolio and supports the Exploration and Production business and the Refining and Marketing business by providing reliable supply and marketing activities and opportunistic commodity trading, as well as offering expertise on asset optimizations and acquisitions.

"During 2008, price volatility and the global banking and financial crisis worked to reduce the level of activity by some participants in our market, which impacted our operations," says Greg Goff, senior vice president, Commercial. "Despite these challenges, we found continued opportunities for our businesses that enabled us to provide increased financial benefits when compared with 2007."

Commercial expanded its cargo trading in South American distillate markets, and increased sales of natural gas in the United States. The group added marine tonnage, increased its storage capacity in Asia, and expanded its natural gas storage capacity in North America by 8 billion cubic feet. Transport capacity was added for both liquid products and natural gas. Trading activity grew in the French and German natural gas markets, and expanded into the new areas of certified emissions reduction credits and liquefied natural gas.

Through activity at its London trading floor and similar facilities elsewhere, the Commercial organization reliably supplied the company's refineries with cost-advantaged crude oil and marketed their products.

Gregory J. Goff
Senior Vice President, Commercial

2008 Major Accomplishments

- Reliably supplied optimal feedstock to 17 ConocoPhillips refineries.
- Expanded existing businesses; increased strategic trading, storage and transport capacity; and entered new markets.
- Progressed proposals for E-Gas™ technology applications at a coal mine in Kentucky and at the ConocoPhillips refinery in Sweeny, Texas.

The group also is working to broaden utilization of the proprietary ConocoPhillips E-Gas™ technology that can be used to gasify coal and petroleum coke. Commercial is evaluating one proposed project with Peabody Energy in Kentucky, with another under consideration for the ConocoPhillips refinery in Sweeny, Texas.

In addition, Commercial continued reliably supplying and optimizing crude oil feedstock to the company's refineries, while finding favorable markets for the company's own production of crude oil, natural gas and refined products.

Project Development

Maximizing Efficiency and Managing Costs

Despite the volatile economy, industry cost inflation, and fierce competition for experienced workers, during 2008 Project Development (PD) delivered a number of projects that strengthened ConocoPhillips' position around the world.

"We have worked tirelessly to strengthen our expertise and become a best-in-class organization," says Luc Messier, senior vice president, Project Development. "This is evident in our success, and I believe we have the project management know-how and experience to be a preferred partner on projects around the globe."

PD achieved improved safety performance in 2008, with a 43 percent decline in its recordable incident rate from 2007.

It also completed a number of large upstream and downstream projects. Among them was the Bohai Bay floating production, storage and offloading vessel, one of the world's largest with 2 million barrels of capacity. In addition, the Britannia Satellites phase I project in the United Kingdom involved simultaneous development of the Callanish oil field and the Brodgar gas condensate field. The Su Tu Vang development project in Vietnam included construction of a central processing platform with capacity to process 100,000 barrels per day, and modification of a floating vessel to store and export crude oil.

Additional milestones included startup of Russia's Yuzhno Khylchuyu (YK) field; completion of the Freeport liquefied natural gas receiving terminal construction in Texas; replacement of a boiler at the Trainer, Pa., refinery; and completion of a fluidized catalytic converter at the Los Angeles, Calif., refinery that included construction of a wet gas scrubber and wet electrostatic precipitator to reduce emissions.

Deployment of this massive floating production, storage and offloading vessel, one of the world's largest, is part of the company's major continuing oil development program in China's Bohai Bay.

Luc J. Messier
Senior Vice President, Project Development

The organization improved its engineering standards, systems and tools, and took key steps to enhance the skills and knowledge of its work force.

With 150 projects in development, during 2009 the organization will focus on delivering safe, predictable and competitive projects in a highly efficient manner. The group also will work with business partners and suppliers to manage and reduce costs.

"We face new challenges during 2009 that we could not have imagined a year ago, but we have the experience as well as the personnel, systems and tools necessary to respond to the new industry operating environment," says Messier.

2008 Major Accomplishments

- Optimized management of 150-project development portfolio; progressing the highest-potential projects.
- Enhanced transactional efficiency through new global requisition-to-payment system.
- Developed tools to better forecast and control procurement costs.

Emerging Businesses

Leveraging Expertise into New Energy Ventures

Emerging Businesses invests in new technologies beyond the company's existing businesses. A key focus area is the planned 2009 completion of an expansion of the Immingham Combined Heat and Power facility, a 750-megawatt unit near the U.K.'s Humber refinery. It will add 450 megawatts of electricity capacity and 200 tons per hour of steam capacity, making it one of the world's largest and most efficient cogeneration facilities.

ConocoPhillips has also developed the proprietary E-Gas™ technology, a proven technique that produces synthesis gas for use in electrical power generation or chemicals manufacturing.

In addition to licensing this technology to others, ConocoPhillips is evaluating two proposed development projects. One, a joint venture with Peabody Energy, would gasify coal at a mine in Kentucky. The other would gasify petroleum coke at the company's Sweeny, Texas, refinery. The byproduct carbon dioxide produced could be utilized in enhanced oil recovery or carbon capture and storage projects.

2008 Major Accomplishment

- Progressed toward 2009 completion of Immingham expansion, which will make this one of world's largest and most efficient cogeneration facilities.

LUKOIL Investment

Ramping Up Production in a Promising Arctic Region

ConocoPhillips has a 20 percent equity ownership in LUKOIL, a Russia-based integrated energy company active in about 30 countries. This investment provides ConocoPhillips with exposure to Russia's vast oil and natural gas resources and to LUKOIL's significant refining and marketing interests.

The company's investment in LUKOIL accounted for 20 percent of ConocoPhillips' 2008 barrels-of-oil-equivalent-per-day (BOED) production.

"We are very pleased with the operational results posted by LUKOIL during the year, and with the close relationship we have established with LUKOIL's executives and technical employees," says Don Wallette, president, Russia and Caspian Region. "We are now working to broaden our relationship by identifying new joint venture opportunities, both inside and outside Russia."

ConocoPhillips has a 30 percent interest in the Naryanmarneftegaz joint venture with LUKOIL. During 2008, the venture initiated production from the first development stage of the large Yuzhno Khylchuyu (YK) oil field located in Russia's Timan-Pechora province. Peak production of 150,000 gross barrels per day (BD) is expected in 2009.

An important component of the strategic alliance with LUKOIL is an exchange program in which managers and specialists from both companies work and train in each other's offices. This promotes rapid knowledge transfer, creating significant value through new technology applications and improved business processes.

LUKOIL's 2008 milestones included commissioning of the Varandey offshore oil loading and export terminal, the first such facility in Arctic waters. LUKOIL acquired a power company, TGK-8, which is a major provider of electricity and heat in southern Russia and a leading natural gas consumer. In Uzbekistan, LUKOIL completed its acquisition of a 100 percent interest in a production sharing agreement on oil, natural gas and condensate fields in the Southwest Gissar and Ustyurt regions, and agreed to form a joint venture with ERG S.p.A. of Italy to operate the strategically located ISAB refinery in Sicily. Additionally, following three years of reconstruction work, LUKOIL restarted the Odessa refinery in the Ukraine.

ConocoPhillips' estimated share of LUKOIL's 2008 production was 445,000 BOED and refining crude oil throughput was 229,000 BD.

2008 Major Accomplishments

- Started up phase I production of major Yuzhno Khylchuyu oil field.
- Commissioned first offshore oil loading and export terminal in Arctic waters.

LUKOIL Financial and Operating Results

	2008	2007
Net income (loss) (MM)	**$ (5,488)**	$ 1,818
Adjusted earnings (MM)	**$ 1,922**	$ 1,818
Net crude oil production (MBD)	**386**	401
Net natural gas production (MMCFD)	**356**	256
Net refining throughput (MBD)	**229**	214

Midstream

Broadening Exposure in Key Drilling Trends

During 2008, DCP Midstream, LLC, a 50/50 joint venture between ConocoPhillips and Spectra Energy, moved to expand its presence in several important U.S. producing basins, while capturing benefits from efforts to enhance reliability. The venture is the largest domestic producer of natural gas liquids, and among the top three natural gas and natural gas liquids gathering, processing and marketing companies.

"We enhanced our leadership in the midstream business sector during the year, and new reliability initiatives benefited not only the bottom line, but just as importantly our customers and the environment," says Thomas O'Connor, president, chairman and chief executive officer, DCP Midstream.

To help ensure the safe, reliable and uninterrupted flow of products, DCP Midstream implemented measures to monitor the financial impact of disruptions, established additional preventive maintenance practices, worked to minimize downtime during overhauls, and upgraded gas compression, electrical, instrumentation and controls capabilities.

DCP Midstream and its master limited partnership, DCP Midstream Partners, broadened their operations in two key drilling trends by completing two acquisitions during 2008. These included the acquisition of Michigan Pipeline & Processing, LLC in the Antrim shale trend in Michigan; and the acquisition of the Cimarron River Pipeline in Oklahoma's Anadarko Basin. The latter added more than 400 miles of pipeline and 66,000 horsepower of field compression.

The company's Midstream joint venture, the largest U.S. producer of natural gas liquids, took steps to enhance its presence in emerging areas of industry activity during 2008.

Planned construction projects announced included a $150 million multiyear investment to construct 20 miles of gathering pipeline, compression and gas-handling facilities in Colorado's Piceance Basin, and a $56 million pipeline project to access growing volumes in the Minden field of East Texas.

The company's Midstream segment also includes an equity interest in Phoenix Park Gas Processors Limited in Trinidad, and interests in liquids fractionation plants in New Mexico, Texas and Kansas.

Midstream's net income for 2008 was $541 million, with ConocoPhillips' net natural gas liquids extraction totaling 188,000 barrels per day (BD), including 180,000 BD from its interest in DCP Midstream. ConocoPhillips' share of DCP Midstream's raw natural gas throughput was 3.1 billion cubic feet per day.

2008 Major Accomplishments

- Completed acquisitions to enhance presence in key Antrim shale (Michigan) and Anadarko Basin (Oklahoma) drilling trends.
- Announced construction projects to strengthen capabilities in Piceance Basin (Colorado) and Minden field (Texas) drilling trends.
- Achieved high operating reliability and safety.

Chemicals

MARLEX
MARLEX
MARLEX

Corporate Staffs

Technology

Stephen R. Brand
Senior Vice President, Technology

Exploring New Energy Frontiers

ConocoPhillips is engaged in a broad range of technology innovations aimed to improve recovery of conventional and nonconventional hydrocarbons; optimize refining operations; produce alternative energy and biofuels; develop sulfur removal and carbon capture and storage capability; and reduce the company's environmental footprint.

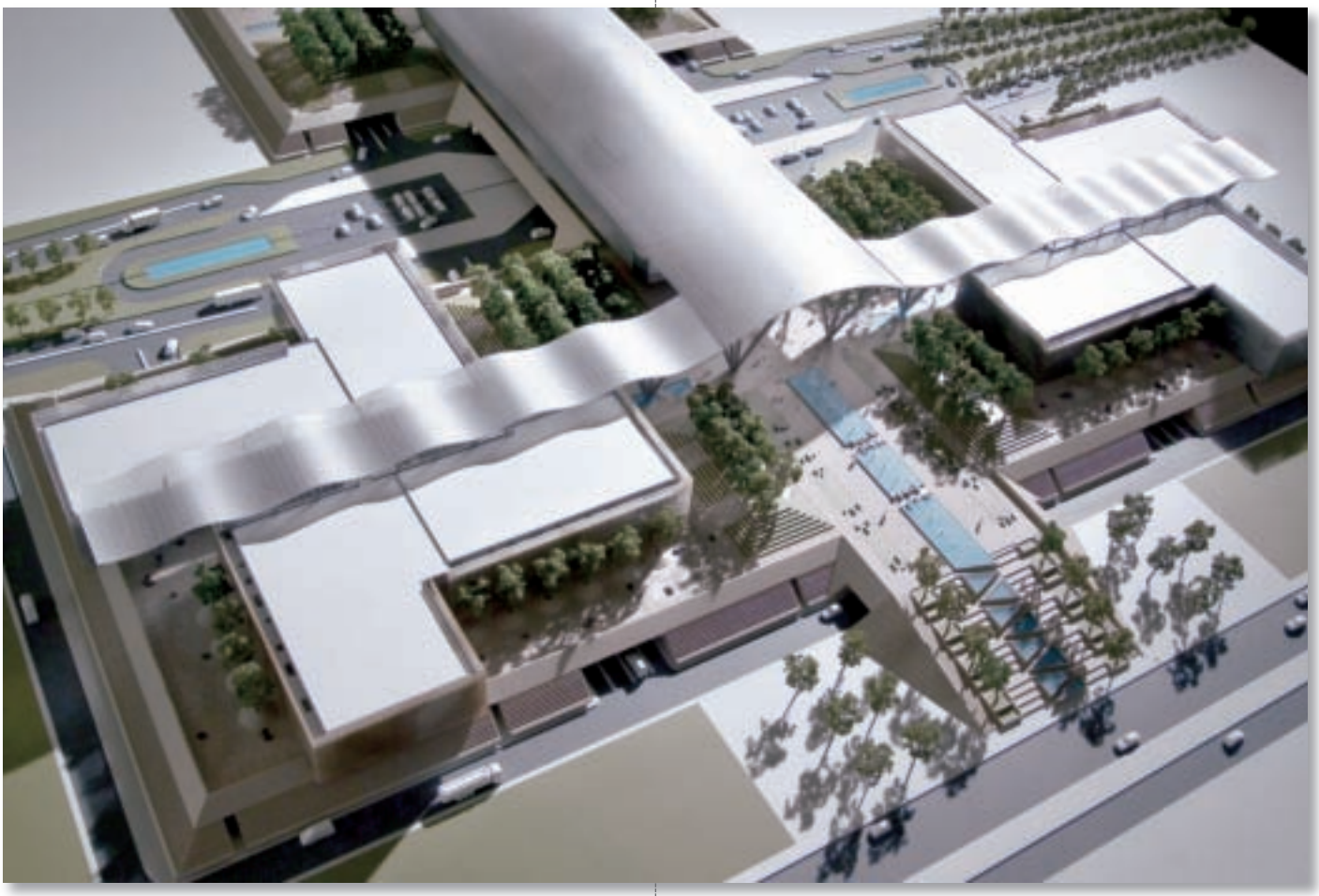
"Since society needs fossil fuels to power the global economy and serve as bridging fuels until tomorrow's energy sources are ready, we are working to bring our products to market in cleaner forms, while undertaking research on alternative energy," says Stephen Brand, senior vice president, Technology.

Much of this research focuses on more efficiently exploiting existing oil and natural gas reserves and finding new resources. Initiatives include implementing analytical tools such as time-lapse (4-D) seismic surveys and computer applications that simulate reservoir fluid flow, and on predicting hydraulic fracture results and developing intelligent systems. Additionally, innovations in the nanotechnology and biotechnology sciences are intended to improve reservoir monitoring and production performance. Advancements to facilitate exploration include advanced seismic imaging, sub-salt definition tools, and earth-systems modeling.

ConocoPhillips is researching methods to reduce energy consumption and optimize process efficiency at its refineries, and to reduce water consumption, remove impurities from crude oil feedstock and refined products, and mitigate greenhouse gas emissions.

The company is working to enhance the steam-assisted gravity drainage (SAGD) technique to optimize production of heavy oil and bitumen from the Canadian oil sands. It is also testing the co-injection of various solvents and carbon dioxide into oil sands reservoirs to potentially increase production while reducing costs and lowering emissions. Other research is under way to develop environmentally friendly technologies to generate steam for use in the oil recovery process.

Upon its completion during 2009 at a business park in Qatar, the Global Water Sustainability Center will research methods to conserve and more efficiently utilize this precious resource.



ConocoPhillips is advancing several initiatives on alternative fuels. The company is collaborating with Iowa State University and the U.S. Department of Energy's (DOE) National Renewable Energy Laboratory on research into cellulosic biomass conversion technologies that could produce liquid fuels. It sponsors research at the Colorado Center for Biorefining and Biofuels to develop fuels from other sources, including algae. A joint effort with Archer Daniels Midland seeks to develop fuels from agricultural waste and thus enable biomass to become a refinery feedstock.

Natural gas hydrates are an enormous undeveloped energy resource found on the world's marine continental shelves and in Arctic regions. ConocoPhillips is researching a promising company-developed technology to extract methane from these deposits. To advance this work, the DOE has selected ConocoPhillips to perform the first field trial of this technology.

The company is participating in a number of consortiums testing various carbon dioxide capture and conversion technologies at several locations worldwide, and is undertaking internal research on this challenge. It also is identifying potential storage sites at depleted oil and natural gas fields.

To protect precious water resources, ConocoPhillips is working to develop a global center to research water sustainability solutions for petroleum, petrochemical, municipal and agricultural applications. The center, in Qatar, is expected to open in 2009. Negotiations also are under way on a proposed technology center in Abu Dhabi to research sour gas-related technologies.

Planning and Strategy

Jeff W. Sheets

Senior Vice President, Planning and Strategy

Providing Business Analysis and Direction

Planning and Strategy (P&S) helps provide ConocoPhillips with strategic direction by performing economic and industry research and planning, and assisting with implementation of key business transactions. Additionally, P&S helps ConocoPhillips address such broad

Reinforcing the company's commitment to sound environmental stewardship is the work of the ConocoPhillips Sustainable Development and Climate Change team.

public concerns as energy supply and security, sustainable development and climate change by assessing these issues and developing effective company positions and responses.

P&S manages the company's strategic objectives and long-range business planning by continually monitoring and analyzing the global business and economic environment, and the specific challenges they pose to the energy industry.

"By developing planning scenarios, forecasting pricing and evaluating new and existing energy sources, we assist management in directing the long-term business plan and operating budget, thus optimizing our future investments," says Jeff Sheets, senior vice president, Planning and Strategy.

In 2008, P&S helped ConocoPhillips complete a number of transactions that broadened the company's opportunity portfolio, including the agreement with Origin Energy to create a long-term Australasian natural gas business focused on coalbed methane production and liquefied natural gas processing and sales, as well as a Memorandum of Understanding with Petrobras to investigate opportunities in the upstream, downstream and biofuels businesses.

The organization also works to generate future opportunities in wind, solar, geothermal power, and other alternative energy fields.

"These activities are intended to advance new technologies and develop the supply diversity that will be needed to meet society's future energy demand," says Sheets.

P&S oversees the company's strategic integration of sustainable development and the challenge of climate change. ConocoPhillips' commitment to sustainability stems from its fundamental intent to thrive as an enterprise by providing the energy that the world needs for modern life, while practicing sound environmental and social responsibility. P&S oversees the company's progress on its nine sustainable development commitments, which encompass such issues as water and biodiversity stewardship, positive community impact, and efficient use of resources. The group is responsible for environmental and social positions and strategies. It publishes a sustainable development report that measures environmental protection, economic growth and social improvement.

In addition, the company belongs to the U.S. Climate Action Partnership, an organization of business and environmental groups that supports enactment of a mandatory national framework to slow, stop and reverse the growth of greenhouse gas emissions. ConocoPhillips is the only U.S.-based integrated energy company to support this position. The company regularly measures and forecasts its emissions, reports them publicly, and has implemented a Climate Change Action Plan to manage them.

ConocoPhillips personnel provide a broad range of vital professional and support services that enhance the competitiveness and efficiency of the company's global business units.

Legal

Janet Langford Kelly
Senior Vice President, Legal, General Counsel and Corporate Secretary

Ensuring Lawful and Ethical Performance

With professional staff and support personnel in 15 offices worldwide, the ConocoPhillips Legal organization assists with the design and negotiation of the company's transactions by documenting contractual arrangements, advising on commercial matters, protecting intellectual property, defending litigation, and prosecuting claims.

"Supporting our businesses in more than 30 countries requires an organization with worldwide resources," says Janet Langford Kelly, senior vice president, Legal, general counsel and corporate secretary. "Our lawyers participate on a variety of project teams, combining specialized knowledge of each country's laws and legal systems with the industry knowledge, negotiation experience and contract expertise that enable us to complete complex business transactions."

In 2008, Legal assisted with more than 80 upstream development projects and numerous business transactions, and with the disposition of U.S. retail marketing assets.

While compliance with the law is primarily the responsibility of all management and employees, ConocoPhillips lawyers facilitate the fulfillment of this responsibility through training and counseling activities. All employees are required to participate in periodic training regarding the company's Code of Business Ethics and Conduct, which details expectations set by senior management and the board of directors for ethical behavior and legal compliance. Employees can contact management or an ethics helpline for ongoing guidance or to report ethics issues.

With the security of company employees and assets in constant focus, ConocoPhillips security personnel conduct risk assessments, establish precautionary measures, respond to emergency situations and provide investigatory services.

"As a critical partner in the success of our businesses around the world, Legal always seeks to add value," says Kelly. "We take pride in developing and maintaining an expert legal staff that is valued by our clients and recognized as energy industry leaders."

Global Systems and Services

Gene L. Batchelder
Senior Vice President, Services, and Chief Information Officer

Leveraging Business Support Capabilities

The ConocoPhillips Global Systems and Services (GSS) group performs a variety of functions for the company's business units, among them financial and information systems services, real estate and facilities management, and aviation.

"These services are essential to all ConocoPhillips business activities, and we strive to provide them in a highly cost-effective manner that represents a competitive advantage," says Gene Batchelder, senior vice president, Services, and chief information officer. "Collectively, our services leverage the capabilities of individual employees, as well as the company as a whole."

At its headquarters in the Bartlesville, Okla., downtown office facilities, GSS led a year-long effort that earned the U.S. Occupational Safety and Health Administration's Voluntary Protection Program STAR status, which recognizes exemplary safety awareness and performance. Bartlesville was ConocoPhillips' first office complex to receive this certification, and was recognized for its best practices in ergonomics, medical programs and employee involvement.

To better accommodate the company's significant international business presence, during 2008 GSS formed a European Financial Services group to implement Europe-specific process improvements and standardization, thus enhancing efficiency and reducing costs.

Additionally, GSS implemented a new computerized system that enables faster electronic data flow to assist the Commercial organization in its worldwide supply, trading, analysis, and reporting functions.

Benefits include improved cash collection, reduced manual data-entry requirements, and the creation of further opportunities to enhance inventory management.

GSS enhanced the company's desktop and other computer networks by improving utilization and efficiency of the servers at the heart of each system.

Through a process called virtualization, a single server can run multiple independent operating systems. This virtualization effort increased average server utilization to 65 percent from only 3 percent in the past, making possible a 500-unit reduction in the number of servers required. Reductions were realized in electrical power requirements, maintenance expenses and capital expenditures needed for new computer hardware.

Throughout the year, GSS also worked to optimize the company's real estate portfolio to meet changing business needs.

Health, Safety and Environment

Robert A. Ridge
Vice President, Health, Safety and Environment

Protecting Our People and Communities

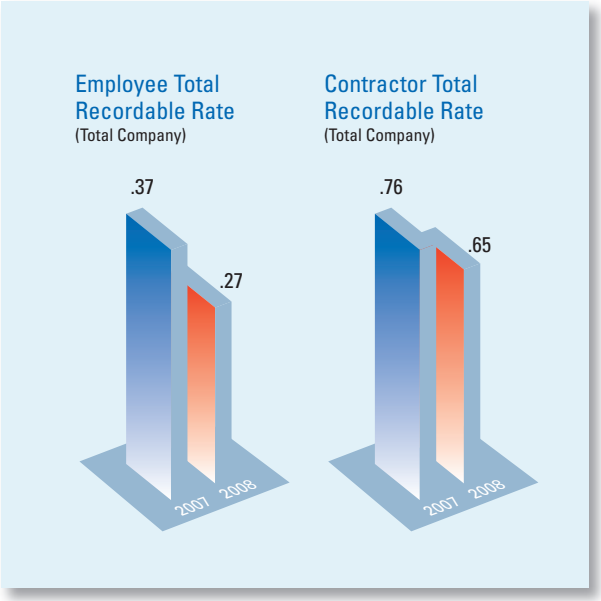
The Health, Safety and Environment (HSE) organization provides tools and support to ConocoPhillips business units and staff groups to help them ensure consistent health, safety and environmental excellence. Through such efforts, the company's total recordable incident rate for employees and contractors fell by 16 percent in 2008, compared with 2007.

Despite this progress, the company experienced several contractor fatalities.

"We deeply regret any loss of life or injuries sustained while working for ConocoPhillips. Our goal is zero incidents, and we are committed to driving continuous improvement to reach that objective," says Bob Ridge, vice president, HSE.

In support of this goal, the HSE Excellence Process recently was implemented. Its assessment tool enables business units to measure their performance and compliance with ConocoPhillips' HSE Management System requirements, identify gaps, and develop improvement plans. Assessments are conducted annually to capture progress and set new targets.

The company also is committed to continuously improving process safety – preventing unintentional releases of hazardous



Through exercises such as an oil spill drill in Illinois, the company's refinery emergency response teams are trained to handle firefighting, hazardous material incidents and confined-space rescue.

ConocoPhillips' Human Resources organization has developed talent management teams to ensure consistent development and staffing opportunities worldwide for key disciplines in each business and corporate function.

materials. New initiatives and performance indicators were established, with objectives incorporated into the HSE Management System. In addition, a Global Process Safety Leadership Committee was formed to provide governance and strategic guidance and develop effective standards, procedures and guidelines to reduce operational risk, increase reliability and enhance worker and community safety.

During 2008, facilities in the U.K. North Sea, Alaska, Colorado and Montana, as well as three Polar Tankers vessels, earned external recognition for exceptional environmental and safety performance.

Additionally, the U.S. Occupational Safety and Health Administration's Voluntary Protection Program (VPP) awarded STAR certification to nine ConocoPhillips locations for their exemplary occupational and safety health standards. The sites included refineries in Sweeny, Texas, and Roxana, Ill.; lubricants plants in Lake Charles, La., Hartford, Ill., Portland, Ore., and Savannah, Ga.; the Alpine field in Alaska; the Wingate fractionators plant in Gallup, N.M.; and the Bartlesville, Okla., office complex. Certification efforts are under way at numerous other locations.

"These actions show our determination to be a leader in health, safety and environmental performance," says Ridge.

Human Resources

Carin S. Knickel
Vice President, Human Resources

Developing an Effective Work Force

ConocoPhillips understands that knowledgeable, dedicated employees with talent and drive are essential to its business success. Consequently, the Human Resources organization works jointly with the company's business units to develop effective people strategies. These strategies are deployed globally in order to prepare all ConocoPhillips employees for the opportunities and challenges of the future.

"We believe that the abilities of our employees and our team approach provide competitive advantages to ConocoPhillips," says

To help educate the youth of America on vital energy issues, ConocoPhillips sponsors an energy education program, which conveys information that school teachers can incorporate into their curricula.

Carin Knickel, vice president, Human Resources. "We support a work environment in which every employee can learn, grow and experience professional success throughout their careers. Our goal is for every employee to have the opportunity to drive the success of the company through their creativity, knowledge and commitment."

In 2008, an enhanced people initiative was launched. By increasing the company's focus on attracting, developing and retaining a diverse and talented work force, ConocoPhillips will be positioned to succeed in all business environments.

As part of the company's focus on people, new learning and development opportunities are being offered to encourage professional growth. An orientation program was launched globally, enabling new employees to quickly integrate into the company and thus increase their productivity. In addition, more than 1,200 leaders were trained to enhance their skills in creating and guiding more effective teams.

Tangible benefits are being realized as a result of ConocoPhillips' people efforts. A recent employee opinion survey indicated significant improvement with regard to how supervisors are engaging employees in both the performance management process and career development conversations.

Government and Public Affairs

Red Cavaney
Senior Vice President, Government and Public Affairs

Engaging Our Communities and Stakeholders

Government and Public Affairs (G&PA) builds and maintains relationships with key internal and external audiences, including employees, members of the public, government and the media; and works to enrich the company's global community through social investment, employee volunteerism and charitable giving.

The company's philanthropic contributions totaled $70 million during 2008.

"ConocoPhillips understands the public's expectation that we serve as a responsible member of society," says Red Cavaney, senior vice president, Government and Public Affairs. "Our contributions, volunteer activities and strategic outreach are all intended to make a positive difference in the communities where we live and work."

Responding to research indicating that today's youth lack sufficient access to information on long-term energy issues, G&PA sponsors a program to improve energy education in classrooms across the United States. This effort directly benefitted more than 114,000 students in 2008, and continues in 2009.

G&PA supported ConocoPhillips' call for enactment of a comprehensive U.S. energy policy by developing advocacy opportunities for senior executives. The department also served as the company's liaison with state and federal government officials on legislative and regulatory issues. During 2008 these efforts contributed to the expiration of a 27-year-long U.S. government moratorium on offshore exploration and production. In preparation for the 2008 U.S. elections, the organization provided employees with primers on the voting process and conducted activities encouraging them to vote.

Additionally, G&PA extended the company's efforts to encourage outside innovation through the ConocoPhillips Energy Prize award program in conjunction with Penn State.

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Management's Discussion and Analysis of Financial Condition and Results of Operations

February 25, 2009

Management's Discussion and Analysis is the company's analysis of its financial performance and of significant trends that may affect future performance. It should be read in conjunction with the financial statements and notes, and supplemental oil and gas disclosures. It contains forward-looking statements including, without limitation, statements relating to the company's plans, strategies, objectives, expectations and intentions, that are made pursuant to the "safe harbor" provisions of the Private Securities Litigation Reform Act of 1995. The words "intends," "believes," "expects," "plans," "scheduled," "should," "anticipates," "estimates" and similar expressions identify forward-looking statements. The company does not undertake to update, revise or correct any of the forward-looking information unless required to do so under the federal securities laws. Readers are cautioned that such forward-looking statements should be read in conjunction with the company's disclosures under the heading: "CAUTIONARY STATEMENT FOR THE PURPOSES OF THE 'SAFE HARBOR' PROVISIONS OF THE PRIVATE SECURITIES LITIGATION REFORM ACT OF 1995," beginning on page 52.

Business Environment and Executive Overview

ConocoPhillips is an international, integrated energy company. We are the third-largest integrated energy company in the United States, based on market capitalization. We have approximately 33,800 employees worldwide, and at year-end 2008 had assets of $143 billion. Our stock is listed on the New York Stock Exchange under the symbol "COP."

Our business is organized into six operating segments:

- **Exploration and Production (E&P)** — This segment primarily explores for, produces, transports and markets crude oil, natural gas and natural gas liquids on a worldwide basis.
- **Midstream** — This segment gathers, processes and markets natural gas produced by ConocoPhillips and others, and fractionates and markets natural gas liquids, predominantly in the United States and Trinidad. The Midstream segment primarily consists of our 50 percent equity investment in DCP Midstream, LLC.
- **Refining and Marketing (R&M)** — This segment purchases, refines, markets and transports crude oil and petroleum products, mainly in the United States, Europe and Asia.
- **LUKOIL Investment** — This segment consists of our equity investment in the ordinary shares of OAO LUKOIL, an international, integrated oil and gas company headquartered in Russia. At December 31, 2008, our ownership interest was 20 percent based on issued shares and 20.06 percent based on estimated shares outstanding.
- **Chemicals** — This segment manufactures and markets petrochemicals and plastics on a worldwide basis. The Chemicals segment consists of our 50 percent equity investment in Chevron Phillips Chemical Company LLC (CPChem).
- **Emerging Businesses** — This segment represents our investment in new technologies or businesses outside our normal scope of operations.

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

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

Crude oil and natural gas prices, along with refining margins, are the most significant factors in our profitability, and are driven by market factors over which we have no control. However, from a competitive perspective, there are other important factors we must manage well to be successful, including:

- **Operating our producing properties and refining and marketing operations safely, consistently and in an environmentally sound manner.** Safety is our first priority, and we are committed to protecting the health and safety of everyone who has a role in our operations and the communities in which we operate. Maintaining high utilization rates at our refineries and minimizing downtime in producing fields enable us to capture the value available in the market in terms of prices and margins. During 2008, our worldwide refining capacity utilization rate was 90 percent, compared with 94 percent in 2007. The lower rate primarily reflects reduced throughput at our Wilhelmshaven, Germany, refinery due to economic conditions, as well as higher unplanned downtime including impacts from hurricanes in the U.S. Gulf Coast region. Concerning the environment, we strive to conduct our operations in a manner consistent with our environmental stewardship principles.
- **Adding to our proved reserve base.** We primarily add to our proved reserve base in three ways:
  - Successful exploration and development of new fields.
  - Acquisition of existing fields.
  - Applying new technologies and processes to improve recovery from existing fields.

  Through a combination of all three methods listed above, we have been successful in the past in maintaining or adding to our production and proved reserve base. Although it cannot be assured, we anticipate being able to do so in the future. In the three years ending December 31, 2008, our reserve replacement was 124 percent, including the impacts of the Burlington Resources acquisition, additional equity investments in LUKOIL, the FCCL Oil Sands Partnership with EnCana, the Australia Pacific LNG joint venture with Origin Energy, and the expropriation of our Venezuelan oil assets.

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

- **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, are high priorities. We monitor these costs using various methodologies that are reported to senior management monthly, on both an absolute-dollar basis and a per-unit basis. Because managing operating and overhead costs is critical to maintaining competitive positions in our industries, cost control is a component of our variable compensation programs. In response to the current depressed market environment, we expect to reduce our work force in 2009, reduce the headcount of contractors, and continue to emphasize cost discipline throughout our operations.

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

- **Selecting the appropriate projects in which to invest our capital dollars.** We participate in capital-intensive industries. As a result, we must often invest significant capital dollars to explore for new oil and gas fields, develop newly discovered fields, maintain existing fields, or continue to maintain and improve our refinery complexes. We invest in those projects that are expected to provide an adequate financial return on invested dollars. However, there are often long lead times from the time we make an investment to the time that investment is operational and begins generating financial returns.

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

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

- **Managing our asset portfolio.** We continue to evaluate opportunities to acquire assets that will contribute to future growth at competitive prices. The 2006 Burlington Resources acquisition, the 2007 EnCana business ventures, and the 2008 Origin Energy joint venture are examples of such activity. We also continually assess our assets to determine if any no longer fit our strategic plans and should be sold or otherwise disposed. This management of our asset portfolio is important to ensuring our long-term growth and maintaining adequate financial returns. In 2008, we completed the disposition of our retail marketing assets in Norway, Sweden and Denmark, and we also sold all of our E&P properties in Argentina and the Netherlands. We closed on the sale of a large part of our U.S. retail marketing assets in January 2009.
- **Developing and retaining a talented work force.** We strive to attract, train, develop and retain individuals with the knowledge and skills to implement our business strategy and who support our values and ethics. Throughout the company, we focus on the continued learning, development and technical training of our employees. Professional new hires participate in structured development programs designed to accelerate their technical and functional skills.

Our key performance indicators are shown in the statistical tables provided at the beginning of the operating segment sections that follow. These include crude oil, natural gas and natural gas liquids prices and production, refining capacity utilization, and refinery output.

Other significant factors that can affect our profitability include:

- **Impairments.** As mentioned above, we participate in capital-intensive industries. At times, our investments become impaired when our reserve estimates are revised downward, when crude oil or natural gas prices, or refinery margins decline significantly for long periods of time, or when a decision to dispose of an asset leads to a write-down to its fair market value. We may also invest large amounts of money in exploration blocks which, if exploratory drilling proves unsuccessful, could lead to a material impairment of leasehold values. Before-tax impairments in 2008, excluding the goodwill impairment discussed below and a $7.4 billion impairment related to our LUKOIL investment, totaled $1.7 billion. This amount compares with $0.4 billion of impairments, excluding the impairment of expropriated assets (discussed below), in 2007.
- **Goodwill.** At year-end 2008, we had $3.8 billion of goodwill on our balance sheet, compared with $29.3 billion at year-end 2007. In 2008, we recorded a $25.4 billion complete impairment of our E&P segment goodwill, primarily as a function of decreased year-end commodity prices and the decline in our market capitalization. For additional information, see Note 9 — Goodwill and Intangibles, in the Notes to Consolidated Financial Statements. Deterioration of market conditions in the future could lead to other goodwill impairments that may have a substantial negative, though noncash, effect on our profitability.

- **Effective tax rate.** Our operations are located in countries with different tax rates and fiscal structures. Accordingly, even in a stable commodity price and fiscal/regulatory environment, our overall effective tax rate can vary significantly between periods based on the "mix" of pretax earnings within our global operations.
- **Fiscal and regulatory environment.** As commodity prices and refining margins fluctuated upward over the last several years, certain governments have responded with changes to their fiscal take. These changes have generally negatively impacted our results of operations, and further changes to government fiscal take could have a negative impact on future operations. In June 2007, our Venezuelan oil projects were expropriated, and we recorded a $4.5 billion after-tax impairment (see the "Expropriated Assets" section of Note 10 — Impairments, in the Notes to Consolidated Financial Statements). The company was also negatively impacted by increased production taxes enacted by the state of Alaska in the fourth quarter of 2007. In October 2007, the government of Ecuador increased the tax rate of the Windfall Profits Tax Law implemented in 2006, increasing the amount of government royalty entitlement on crude oil production to 99 percent of any increase in the price of crude oil above a contractual reference price. In Canada, the Alberta provincial government changed the royalty structure for Crown lands, effective January 1, 2009, so that a component of the new royalty rate is tied to prevailing prices. In October 2008, we and our co-venturers signed definitive agreements for the proportional dilution of our equity interests in the Republic of Kazakhstan's North Caspian Sea Production Sharing Agreement, which includes the Kashagan field, to allow the state-owned energy company to increase its ownership percentage effective January 1, 2008. Partially offsetting the above fiscal take increases were lower corporate income tax rates enacted by Canada and Germany during 2007. These tax rate reductions applied to all corporations and were not exclusive to the oil and gas industry.

Segment Analysis

The E&P segment's results are most closely linked to crude oil and natural gas prices. These are commodity products, the prices of which are subject to factors external to our company and over which we have no control. Industry crude oil prices for West Texas Intermediate (WTI) were higher in 2008, compared with 2007, averaging $99.56 per barrel in 2008, an increase of 38 percent. The increase was driven by concerns during the first half of 2008 of adequate supplies given the strong oil demand growth in developing Asia and the Middle East. The average annual price for WTI moderated due to the economic crisis in the second half of 2008 that impacted demand from all regions of the world. Industry natural gas prices for Henry Hub increased 32 percent during 2008 to an average price of $9.04 per million British thermal units (MMBTU), primarily due to increased demand from the industrial and electric power sector during the first half of 2008 and higher oil prices. These factors were moderated by higher domestic production and lower demand, which led to higher storage in the second half of 2008.

The Midstream segment's results are most closely linked to natural gas liquids prices. The most important factor on the profitability of this segment is the results from our 50 percent equity investment in DCP Midstream. DCP Midstream's natural gas liquids prices increased 11 percent in 2008.

Refining margins, refinery utilization, cost control and marketing margins primarily drive the R&M segment's results. Refining margins are subject to movements in the cost of crude oil and other feedstocks, and the sales prices for refined products, both of which are subject to market factors over which we have no control. Industry refining margins in the United States were lower overall in comparison with 2007. The primary factor contributing to the reduced refining margins in 2008 was a decrease in gasoline demand.

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

The Chemicals segment consists of our 50 percent interest in CPChem. The chemicals and plastics industry is mainly a commodity-based industry where the margins for key products are based on market factors over which CPChem has little or no control. CPChem is investing in feedstock-advantaged areas in the Middle East with access to large, growing markets, such as Asia.

The Emerging Businesses segment represents our investment in new technologies or businesses outside our normal scope of operations. Activities within this segment are currently focused on power generation and innovation of new technologies, such as those related to conventional and nonconventional hydrocarbon recovery (including heavy oil), refining, alternative energy, biofuels and the environment. Some of these technologies have the potential to become important drivers of profitability in future years.

Results of Operations

Consolidated Results

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

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

2008 vs. 2007

The lower results in 2008 were primarily the result of:

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

These items were partially offset by:

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

2007 vs. 2006

The lower results in 2007 were primarily the result of:

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

These items were partially offset by:

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

Statement of Operations Analysis

2008 vs. 2007

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

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

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

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

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

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

Impairments increased from $5,030 million in 2007 to $34,539 million in 2008. This increase reflects a $25,443 million goodwill impairment recorded during 2008 in our E&P segment. Also contributing to the increase was a $7,410 million impairment of our LUKOIL investment taken during 2008. These 2008 impairments were partially offset by a 2007 impairment of $4,588 million related to the expropriation of our oil interests in Venezuela.

Other impairments increased $1,244 million during 2008 primarily due to property impairments taken in response to a significantly diminished outlook for crude oil and natural gas prices, refining margins and power spreads, as well as in response to revised capital spending plans. For additional information, see Note 7 — Investments, Loans, and Long-Term Receivables, Note 9 — Goodwill and Intangibles, and Note 10 — Impairments, in the Notes to Consolidated Financial Statements.

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

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

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

2007 vs. 2006

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

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

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

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

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

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

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

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

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

Segment Results

E&P

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

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

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

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

	2008	2007	2006
	Thousands of Barrels Daily		
Operating Statistics			
Crude oil produced			
Alaska	**244**	261	263
Lower 48	**91**	102	104
United States	**335**	363	367
Europe	**214**	210	245
Asia Pacific	**91**	87	106
Canada	**25**	19	25
Middle East and Africa	**78**	81	106
Other areas	**9**	10	7
Total consolidated	**752**	770	856
Equity affiliates*			
Canada	**30**	27	—
Russia and Caspian	**24**	15	15
Other areas	—	42	101
	806	854	972
Natural gas liquids produced			
Alaska	**17**	19	17
Lower 48	**74**	79	62
United States	**91**	98	79
Europe	**19**	14	13
Asia Pacific	**16**	14	18
Canada	**25**	27	25
Middle East and Africa	**2**	2	1
	153	155	136
	Millions of Cubic Feet Daily		
Natural gas produced**			
Alaska	**97**	110	145
Lower 48	**1,994**	2,182	2,028
United States	**2,091**	2,292	2,173
Europe	**954**	961	1,065
Asia Pacific	**609**	579	582
Canada	**1,054**	1,106	983
Middle East and Africa	**114**	125	142
Other areas	**14**	19	16
Total consolidated	**4,836**	5,082	4,961
Equity affiliates*			
Asia Pacific	**11**	—	—
Other areas	—	5	9
	4,847	5,087	4,970
	Thousands of Barrels Daily		
Mining operations			
Syncrude produced	**22**	23	21

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

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

The E&P segment explores for, produces, transports and markets crude oil, natural gas and natural gas liquids on a worldwide basis. It also mines deposits of oil sands in Canada to extract the bitumen and upgrade it into a synthetic crude oil. At December 31, 2008, our E&P operations were producing in the United States, Norway, the United Kingdom, Canada, Ecuador, Australia, offshore Timor-Leste in the Timor Sea, Indonesia, China, Vietnam, Libya, Nigeria, Algeria and Russia.

2008 vs. 2007

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

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

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

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

U.S. E&P

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

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

International E&P

Net income from our international E&P operations increased from $367 million in 2007 to $6,976 million in 2008. The increase was attributed to the impact of the Venezuelan impairment on our prior-year results and higher crude oil, natural gas and natural gas liquids prices. The increase was partially

offset by higher depreciation expense due to increased rates and new assets being placed in service, increased taxes other than income, higher operating costs, and the absence of a 2007 benefit related to release of escrowed funds associated with our Hamaca joint venture in Venezuela.

International E&P production averaged 992,000 BOE per day in 2008, a decrease of 2 percent from 1,014,000 in 2007. Decreases in production were caused by field decline and the expropriation of our Venezuelan oil interests. These decreases were mostly offset by increased production from new developments in the United Kingdom, Indonesia, Russia, Norway and Canada. Our Syncrude mining operations produced 22,000 barrels per day in 2008, compared with 23,000 barrels per day in 2007.

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

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

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

2007 vs. 2006

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

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

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

U.S. E&P

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

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

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

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

International E&P

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

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

Midstream

	2008	2007	2006
	Millions of Dollars		
Net Income*	**$ 541**	453	476
**Includes DCP Midstream-related net income:*	***$ 458***	*336*	*385*
	Dollars Per Barrel		
Average Sales Prices			
U.S. natural gas liquids*			
Consolidated	**$56.29**	47.93	40.22
Equity affiliates	**52.08**	46.80	39.45
	Thousands of Barrels Daily		
Operating Statistics			
Natural gas liquids extracted*	**188**	211	209
Natural gas liquids fractionated**	**165**	173	144

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

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

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

2008 vs. 2007
Net income from the Midstream segment increased 19 percent in 2008. The increase was primarily due to higher realized natural gas liquids prices, partially offset by higher operating costs and higher depreciation expense.

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

R&M

	2008	2007	2006
	Millions of Dollars		
Net Income			
United States	**$1,540**	4,615	3,915
International	**782**	1,308	566
	$2,322	5,923	4,481
	Dollars Per Gallon		
U.S. Average Sales Prices*			
Gasoline			
Wholesale	**$ 2.65**	2.27	2.04
Retail	**2.81**	2.42	2.18
Distillates — wholesale	**3.06**	2.29	2.11
	Thousands of Barrels Daily		
Operating Statistics			
Refining operations*			
United States			
Crude oil capacity**	**2,008**	2,035	2,208
Crude oil runs	**1,849**	1,944	2,025
Capacity utilization (percent)	**92%**	96	92
Refinery production	**2,035**	2,146	2,213
International			
Crude oil capacity**	**670**	687	651
Crude oil runs	**567**	616	591
Capacity utilization (percent)	**85%**	90	91
Refinery production	**575**	633	618
Worldwide			
Crude oil capacity**	**2,678**	2,722	2,859
Crude oil runs	**2,416**	2,560	2,616
Capacity utilization (percent)	**90%**	94	92
Refinery production	**2,610**	2,779	2,831
Petroleum products sales volumes			
United States			
Gasoline	**1,128**	1,244	1,336
Distillates	**893**	872	850
Other products	**374**	432	531
	2,395	2,548	2,717
International	**645**	697	759
	3,040	3,245	3,476

**Excludes excise taxes.*

**Includes our share of equity affiliates, except for our share of LUKOIL, which is reported in the LUKOIL Investment segment.*
***Weighted-average crude oil capacity for the periods. Actual capacity at year-end 2007 and 2006 was 2,037,000 and 2,208,000 barrels per day, respectively, for our domestic refineries, and 669,000 and 693,000 barrels per day, respectively, for our international refineries.*

The R&M segment's operations encompass refining crude oil and other feedstocks into petroleum products (such as gasoline, distillates and aviation fuels); buying, selling and transporting crude oil; and buying, transporting, distributing and marketing petroleum products. R&M has operations mainly in the United States, Europe and the Asia Pacific region.

2008 vs. 2007
Net income from the R&M segment decreased 61 percent in 2008. The results were lower due to decreases in U.S. refining margins and volumes, increased property impairments, higher operating costs, a reduced benefit from asset rationalization efforts, and lower international marketing and refining volumes due to asset sales. During 2008, our R&M segment had property impairments totaling $511 million after-tax, mostly due to a significantly diminished outlook for refining margins. These R&M decreases were partially offset by higher international marketing margins.

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

U.S. R&M

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

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

International R&M

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

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

2007 vs. 2006

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

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

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

U.S. R&M

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

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

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

International R&M

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

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

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

LUKOIL Investment

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

**Represents our net share of our estimate of LUKOIL's production and processing.*

This segment represents our investment in the ordinary shares of LUKOIL, an international, integrated oil and gas company headquartered in Russia, which we account for under the equity method. At December 31, 2008, our ownership interest in LUKOIL was 20 percent based on authorized and issued shares. Our ownership interest based on estimated shares outstanding, used for equity method accounting, was 20.06 percent at that date.

Because LUKOIL's accounting cycle close and preparation of U.S. generally accepted accounting principles financial statements occur subsequent to our reporting deadline, our equity earnings and statistics for our LUKOIL investment are estimated based on current market indicators, publicly available LUKOIL information, and other objective data. Once the difference between actual and estimated results is known, an adjustment is recorded. This estimate-to-actual adjustment will be a recurring component of future-period results. In addition to our estimated equity share of LUKOIL's earnings, this segment reflects the amortization of the basis difference between our equity interest in the net assets of LUKOIL and the book value of our investment. The segment also includes the costs associated with our employees seconded to LUKOIL.

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

Excluding the impact of the impairment, income from the LUKOIL Investment segment increased 6 percent in 2008. This increase was primarily due to higher estimated realized prices of both refined product and crude oil sales. Partially offsetting these positive impacts were higher estimated extraction taxes and higher estimated crude and refined product export tariff rates, as well as higher estimated operating costs and lower estimated crude volumes.

The adjustment to estimated results for the fourth quarter of 2007, recorded in 2008, decreased net income $16 million, compared with a $19 million decrease to net income recorded in 2007 to adjust the estimated results for the fourth quarter of 2006.

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

Chemicals

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

The Chemicals segment consists of our 50 percent interest in Chevron Phillips Chemical Company LLC (CPChem), which we account for under the equity method. CPChem uses natural gas liquids and other feedstocks to produce petrochemicals. These products are then marketed and sold, or used as feedstocks to produce plastics and commodity chemicals.

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

2007 vs. 2006
Net income from the Chemicals segment decreased 27 percent during 2007, primarily due to lower olefins and polyolefins margins and higher turnaround and weather-related repair costs, offset partially by a capital-loss tax benefit of $65 million recorded in the fourth quarter of 2007.

Emerging Businesses

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

The Emerging Businesses segment represents our investment in new technologies or businesses outside our normal scope of operations. Activities within this segment are currently focused on power generation and innovation of new technologies, such as those related to conventional and nonconventional hydrocarbon recovery (including heavy oil), refining, alternative energy, biofuels, and the environment.

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

2007 vs. 2006

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

Corporate and Other

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

2008 vs. 2007

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

2007 vs. 2006

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

Capital Resources and Liquidity

Financial Indicators

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

**Capital includes total debt, minority interests and common stockholders' equity.*

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

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

Significant Sources of Capital

Operating Activities

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

During 2007, cash flow from operations increased $3,034 million to $24,550 million. Contributing to the improvement over 2006 results was a planned inventory reduction in the 2007 period, partially related to the formation of the WRB downstream business venture; the impact of the

Burlington Resources acquisition late in the first quarter of 2006; and higher worldwide crude oil prices in 2007. These positive factors were partially offset by the absence of dividends from our Venezuelan operations in 2007.

While the stability of our cash flows from operating activities benefits from geographic diversity and the effects of upstream and downstream integration, our short- and long-term operating cash flows are highly dependent upon prices for crude oil, natural gas and natural gas liquids, as well as refining and marketing margins. During 2008 and 2007, we benefited from favorable crude oil and natural gas prices, although these prices deteriorated significantly in the fourth quarter of 2008. Prices and margins are driven by market conditions over which we have no control. Absent other mitigating factors, as these prices and margins fluctuate, we would expect a corresponding change in our operating cash flows.

The level of our production volumes of crude oil, natural gas and natural gas liquids also impacts our cash flows. These production levels are impacted by such factors as acquisitions and dispositions of fields, field production decline rates, new technologies, operating efficiency, weather conditions, the addition of proved reserves through exploratory success, and the timely and cost-effective development of those proved reserves. While we actively manage these factors, production levels can cause variability in cash flows, although historically this variability has not been as significant as that caused by commodity prices.

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

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

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

As discussed in the "Critical Accounting Estimates" section, engineering estimates of proved reserves are imprecise, and therefore, each year reserves may be revised upward or downward due to the impact of changes in oil and gas prices or as more technical data becomes available on reservoirs. In 2008 and 2006, revisions decreased our reserves, while in 2007 revisions increased reserves. It is not possible to reliably predict how revisions will impact reserve quantities in the future. See the "Capital Spending" section for an analysis of proved undeveloped reserves.

In addition, the level and quality of output from our refineries impacts our cash flows. The output at our refineries is impacted by such factors as operating efficiency, maintenance turnarounds, feedstock availability and weather conditions. We actively manage the operations of our refineries and, typically, any variability in their operations has not been as significant to cash flows as that caused by refining margins.

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

Asset Sales

Proceeds from asset sales in 2008 were $1,640 million, compared with $3,572 million in 2007. The amounts for both periods are mainly due to asset rationalization efforts related to the program we announced in April 2006 to dispose of assets that no longer fit into our strategic plans or those that could bring more value by being monetized in the near term. We do not expect any material asset dispositions in 2009 beyond the sale of our U.S. retail marketing assets. In January 2009, we closed on the sale of a large part of these assets, which included seller financing in the form of a $370 million five-year note and letters of credit totaling $54 million.

Commercial Paper and Credit Facilities

At December 31, 2008, we had two revolving credit facilities totaling $9.85 billion, consisting of a $7.35 billion facility, expiring in September 2012, and a $2.5 billion facility scheduled to expire in September 2009 (terminated in early 2009, see the "Shelf Registrations" section below). The $7.35 billion facility was reduced from $7.5 billion during the third quarter of 2008 due to the bankruptcy of Lehman Commercial Paper Inc., one of the revolver participants. The $2.5 billion facility is a 364-day

bank facility entered into during October 2008 to provide additional support of a temporary expansion of our commercial paper program. We expanded our commercial paper program to ensure adequate liquidity after the initial funding of our transaction with Origin Energy. For additional information on the Origin transaction, see Note 7 — Investments, Loans and Long-Term Receivables, in the Notes to Consolidated Financial Statements.

Our revolving credit facilities may be used as direct bank borrowings, as support for issuances of letters of credit totaling up to $750 million, as support for our commercial paper programs, or as support of up to $250 million on commercial paper issued by TransCanada Keystone Pipeline LP, a Keystone pipeline joint venture entity. The revolving credit facilities are broadly syndicated among financial institutions and do not contain any material adverse change provisions or any covenants requiring maintenance of specified financial ratios or ratings. The facility agreements contain a cross-default provision relating to the failure to pay principal or interest on other debt obligations of $200 million or more by ConocoPhillips, or by any of its consolidated subsidiaries.

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

Shelf Registrations

We have a universal shelf registration statement on file with the U.S. Securities and Exchange Commission (SEC) under which we, as a well-known seasoned issuer, have the ability to issue and sell an indeterminate amount of various types of debt and equity securities. Under this shelf registration, in May 2008 we issued notes consisting of $400 million of 4.40% Notes due 2013, $500 million of 5.20% Notes due 2018 and $600 million of 5.90% Notes due 2038. The proceeds from the offering were used at that time to reduce commercial paper and for general corporate purposes.

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

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

We also have on file with the SEC a shelf registration statement under which ConocoPhillips Canada Funding Company I and ConocoPhillips Canada Funding Company II, both wholly owned subsidiaries, could issue an indeterminate amount of senior debt securities, fully and unconditionally guaranteed by ConocoPhillips and ConocoPhillips Company.

Minority Interests

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

In December 2001, in order to raise funds for general corporate purposes, ConocoPhillips and Cold Spring Finance S.a.r.l. formed Ashford Energy Capital S.A. through the contribution of a $1 billion ConocoPhillips subsidiary promissory note and $500 million cash by Cold Spring. Through its initial $500 million investment, Cold Spring is entitled to a cumulative annual preferred return consisting of 1.32 percent plus a three-month LIBOR rate set at the beginning of each quarter. The preferred return at December 31, 2008, was 5.37 percent. In 2008, Cold Spring declined its option to remarket its investment in Ashford. This option remains available in 2018 and at each 10-year anniversary thereafter. If remarketing is unsuccessful, we could be required to provide a letter of credit in support of Cold Spring's investment, or in the event such a letter of credit is not provided, cause the redemption of Cold Spring's investment in Ashford. Should our credit rating fall below investment grade, Ashford would require a letter of credit to support $475 million of the term loans, as of December 31, 2008, made by Ashford to other ConocoPhillips subsidiaries. If the letter of credit is not obtained within 60 days, Cold Spring could cause Ashford to sell the ConocoPhillips subsidiary notes. At December 31, 2008, Ashford held $2.0 billion of ConocoPhillips subsidiary notes and $28 million in investments unrelated to ConocoPhillips. We report Cold Spring's investment as a minority interest because it is not mandatorily redeemable, and the entity does not have a specified liquidation date. Other than the obligation to make payment on the subsidiary notes described above, Cold Spring does not have recourse to our general credit.

Off-Balance Sheet Arrangements

As part of our normal ongoing business operations and consistent with normal industry practice, we enter into numerous agreements with other parties to pursue business opportunities, which share costs and apportion risks among the parties as governed by the agreements. At December 31, 2008, we were liable for certain contingent obligations under the following contractual arrangements:

- **Qatargas 3:** We own a 30 percent interest in Qatargas 3, an integrated project to produce and liquefy natural gas from Qatar's North field. The other participants in the project are affiliates of Qatar Petroleum (68.5 percent) and Mitsui & Co., Ltd. (1.5 percent). Our interest is held through a jointly owned company, Qatar Liquefied Gas Company Limited (3), for which we use the equity method of accounting. Qatargas 3 secured project financing of $4 billion in December 2005, consisting of $1.3 billion of loans from export credit agencies (ECA), $1.5 billion from commercial banks, and $1.2 billion from ConocoPhillips. The ConocoPhillips loan facilities have substantially the same terms as the ECA and commercial bank facilities. Prior to project completion certification, all loans, including the ConocoPhillips loan facilities, are guaranteed by the participants, based on their respective ownership interests. Accordingly, our maximum exposure to this financing structure is $1.2 billion. Upon completion certification, currently expected in 2011, all project loan facilities, including the ConocoPhillips loan facilities, will become nonrecourse to the project participants. At December 31, 2008, Qatargas 3 had $3.0 billion outstanding under all the loan facilities, of which ConocoPhillips provided $835 million, and an additional $76 million of accrued interest.
- **Rockies Express Pipeline LLC:** In June 2006, we issued a guarantee for 24 percent of $2.0 billion in credit facilities issued to Rockies Express Pipeline LLC. Rockies Express is constructing a natural gas pipeline across a portion of the United States. The maximum potential amount of future payments to third-party lenders under the guarantee is estimated to be $480 million, which could become payable if the credit facilities are fully utilized and Rockies Express fails to meet its obligations under the credit agreement. At December 31, 2008, Rockies Express had $1,561 million outstanding under the credit facilities, with our 24 percent guarantee equaling $375 million. In addition, we have a 24 percent guarantee on $600 million of Floating Rate Notes due 2009. It is anticipated that construction completion will be achieved in 2009, and refinancing will take place at that time, making the debt nonrecourse.
- **Keystone Oil Pipeline:** In December 2007, we acquired a 50 percent equity interest in four Keystone pipeline entities (Keystone), to create a joint venture with TransCanada Corporation. Keystone is constructing a crude oil pipeline originating in Alberta, with delivery points in Illinois and Oklahoma. In connection with certain planning and construction activities, we agreed to reimburse TransCanada with respect to a portion of guarantees issued by TransCanada for certain of Keystone's obligations to third parties. Our maximum potential amount of future payments associated with these guarantees is based on our ultimate ownership percentage in Keystone and is estimated to be $180 million, which could become payable if Keystone fails to meet its obligations and the obligations cannot otherwise be mitigated. Payments under the guarantees are contingent upon the partners not making necessary equity contributions into Keystone; therefore, it is considered unlikely payments would be required. All but $8 million of the guarantees will terminate after construction is completed, currently estimated to occur in 2010.

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

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

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

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

Capital Requirements

Our debt balance at December 31, 2008, was $27.5 billion, an increase of $5.8 billion during 2008, and our debt-to-capital ratio was 33 percent at year-end 2008, versus 19 percent at the end of 2007. The increase in the debt-to-capital ratio was mainly due to

noncash impairments taken in the fourth quarter of 2008 and the increase in debt. Our debt-to-capital target range is 20 percent to 25 percent.

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

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

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

In December 2005, we entered into a credit agreement with Qatargas 3, whereby we will provide loan financing of approximately $1.2 billion for the construction of an LNG train in Qatar. This financing will represent 30 percent of the project's total debt financing. Through December 31, 2008, we had provided $835 million in loan financing, and an additional $76 million of accrued interest.

In 2004, we finalized our transaction with Freeport LNG Development, L.P. to participate in an LNG receiving terminal in Quintana, Texas, for which construction began in early 2005. We do not have an ownership interest in the facility, but we do have a 50 percent interest in the general partnership managing the venture, along with contractual rights to regasification capacity of the terminal. We entered into a credit agreement with Freeport to provide loan financing for the construction of the facility. The terminal became operational in June 2008, and in August 2008, the loan was converted from a construction loan to a term loan and consisted of $650 million in loan financing and $124 million of accrued interest. Freeport began making repayments in September 2008, and the loan balance outstanding at December 31, 2008, was $757 million.

In 2004, ConocoPhillips and LUKOIL agreed to the expansion of the Varandey terminal as part of our investment in the OOO Naryanmarneftegaz (NMNG) joint venture. We have an obligation to provide loan financing to Varandey Terminal Company for 30 percent of the costs of the terminal expansion, but we will have no governance or ownership interest in the terminal. Terminal construction was completed in June 2008, and the final loan amount was $275 million at December 2008 exchange rates, excluding accrued interest. Although repayments are not required to start until May 2010, Varandey used available cash to repay $12 million of interest in the second half of 2008. The outstanding accrued interest at December 31, 2008, was $38 million at December exchange rates.

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

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

Contractual Obligations

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

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

(a) Includes $639 million of net unamortized premiums and discounts. See Note 12 — Debt, in the Notes to Consolidated Financial Statements, for additional information.

(b) Represents any agreement to purchase goods or services that is enforceable and legally binding and that specifies all significant terms. Does not include purchase commitments for jointly owned fields and facilities where we are not the operator.

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

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

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

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

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

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

Capital Spending

Capital Expenditures and Investments

	Millions of Dollars			
	2009 Budget	**2008**	2007	2006
E&P				
United States — Alaska	$ 832	**1,414**	666	820
United States — Lower 48	2,668	**3,836**	3,122	2,008
International	5,959	**11,206**	6,147	6,685
	9,459	**16,456**	9,935	9,513
Midstream	7	**4**	5	4
R&M				
United States	1,409	**1,643**	1,146	1,597
International	577	**626**	240	1,419
	1,986	**2,269**	1,386	3,016
LUKOIL Investment	—	**—**	—	2,715
Chemicals	—	**—**	—	—
Emerging Businesses	100	**156**	257	83
Corporate and Other	150	**214**	208	265
	$11,702	**19,099**	11,791	15,596
United States	$ 5,076	**7,111**	5,225	4,735
International	6,626	**11,988**	6,566	10,861
	$11,702	**19,099**	11,791	15,596

Our capital expenditures and investments for the three-year period ending December 31, 2008, totaled $46.5 billion, with 77 percent going to our E&P segment. Included in these amounts was approximately $4.7 billion related to the October 2008 closing of a transaction with Origin Energy to further enhance our long-term Australasian natural gas business through a 50/50 joint venture named Australia Pacific LNG. The joint venture will focus on coalbed methane production from the Bowen and Surat basins in Queensland, Australia, and LNG processing and export sales. For additional information about the Origin transaction, see Note 7 — Investments, Loans and Long-Term Receivables, in the Notes to Consolidated Financial Statements.

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

E&P

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

- Significant U.S. lease acquisitions in the federal waters of the Chukchi Sea offshore Alaska, as well as in the deepwater Gulf of Mexico.
- Alaska activities related to development drilling in the Greater Kuparuk Area, including West Sak; the Greater Prudhoe Bay Area; the Alpine field, including satellite field prospects; and the Cook Inlet Area; as well as initiatives to progress the gas pipeline project named Denali — The Alaska Gas Pipeline; and exploration activities.
- Oil and natural gas developments in the Lower 48, including New Mexico, Texas, Louisiana, Oklahoma, Montana, North Dakota, Colorado, Wyoming, and offshore in the Gulf of Mexico.
- Investment in West2East Pipeline LLC, a company holding a 100 percent interest in Rockies Express Pipeline LLC.
- Development of the Surmont heavy-oil project, capital expenditures related to the FCCL upstream business venture, and development of conventional oil and gas reserves, all in Canada.
- Development drilling and facilities projects in the Greater Ekofisk Area and the Alvheim project, both located in the Norwegian sector of the North Sea.
- The Statfjord Late Life project straddling the offshore boundary between Norway and the United Kingdom.
- The Britannia satellite developments in the U.K. North Sea.
- An integrated project to produce and liquefy natural gas from Qatar's North field.
- Expenditures related to the terms under which we returned to our former oil and natural gas production operations in the Waha concessions in Libya and continued development of these concessions.
- Ongoing development of onshore oil and natural gas fields in Nigeria and ongoing exploration activities both onshore and within deepwater leases.
- The Kashagan field and satellite prospects in the Caspian Sea, offshore Kazakhstan.
- Development of the Yuzhno Khylchuyu (YK) field in the northern part of Russia's Timan-Pechora province through the NMNG joint venture with LUKOIL.
- The initial investment related to the 50/50 joint venture with Origin Energy.
- Projects in offshore Block B and onshore South Sumatra in Indonesia.
- The Peng Lai 19-3 development in China's Bohai Bay and additional Bohai Bay appraisal and adjacent field prospects.
- The Gumusut-Kakap development offshore Sabah, Malaysia.

2009 Capital Expenditures and Investments Budget

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

Capital spending for our Alaskan operations is expected to fund Prudhoe Bay, Kuparuk and Western North Slope operations, including the Alpine satellite fields, as well as initiatives to progress Denali — The Alaska Gas Pipeline, and exploration activities.

In the Lower 48, we expect to make capital expenditures and investments for ongoing development programs in the Permian, San Juan, Williston and Fort Worth basins and the Lobo Trend in South Texas, as well as for development of projects such as the Rockies Express natural gas pipeline.

E&P is directing $6.0 billion of its 2009 capital expenditures and investments budget to international projects. Funds in 2009 will be directed to developing major long-term projects including:

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

Proved Undeveloped Reserves

The net addition of proved undeveloped reserves accounted for 156 percent, 77 percent and 37 percent of our total net additions in 2008, 2007 and 2006, respectively. During these years, we converted, on average, 15 percent per year of our proved undeveloped reserves to proved developed reserves. Of our 2,823 million total BOE proved undeveloped reserves at December 31, 2008, we estimated that the average annual conversion rate for these reserves for the three-year period ending 2011 will be approximately 15 percent.

Costs incurred for the years ended December 31, 2008, 2007 and 2006, relating to the development of proved undeveloped reserves were $4.8 billion, $4.3 billion, and $3.9 billion, respectively. Estimated future development costs relating to the development of proved undeveloped reserves for the years 2009 through 2011 are projected to be $3.9 billion, $3.1 billion, and $2.0 billion, respectively.

Approximately 80 percent of our proved undeveloped reserves at year-end 2008 were associated with 10 major development areas in our E&P segment, and our investment in LUKOIL. Eight of the major development areas within E&P are currently producing and are expected to have proved reserves convert from undeveloped to developed over time as development activities continue and/or production facilities are expanded or upgraded, and include:

- The Ekofisk field in the North Sea.
- The Peng Lai 19-3 field in China.
- Fields in the United States.
- FCCL heavy-oil projects — Christina Lake and Foster Creek in Canada.
- The Surmont heavy-oil project in Canada.

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

R&M

Capital spending for R&M during the three-year period ending December 31, 2008, was primarily for acquiring additional crude oil refining capacity, clean fuels projects to meet new environmental standards, refinery upgrade projects to improve product yields, the operating integrity of key processing units, as well as for safety projects. During this three-year period, R&M capital spending was $6.7 billion, representing 14 percent of our total capital expenditures and investments.

Key projects during the three-year period included:

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

Major construction activities in progress include:

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

2009 Capital Expenditures and Investments Budget

R&M's 2009 capital budget is $2.0 billion, a 12 percent decrease from actual spending in 2008. Domestic spending in 2009 is expected to comprise 71 percent of the R&M budget.

We plan to direct about $1.1 billion of the R&M capital budget to domestic refining, primarily for projects related to sustaining and improving existing business with a focus on safety, regulatory compliance, reliability and capital maintenance. Work continues on projects to expand conversion capability and increase clean product yield, including funding for the San Francisco hydrocracker project. Our U.S. transportation, marketing and specialty businesses are expected to spend about $300 million, including investments in the Keystone project.

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

LUKOIL Investment

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

Emerging Businesses

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

Contingencies

Legal and Tax Matters

We accrue for non-income-tax-related contingencies when a loss is probable and the amounts can be reasonably estimated. If a range of amounts can be reasonably estimated and no amount within the range is a better estimate than any other amount, then the minimum of the range is accrued. In the case of income-tax-related contingencies, we adopted Financial Accounting Standards Board (FASB) Interpretation No. 48, "Accounting for Uncertainty in Income Taxes — an interpretation of FASB Statement No. 109" (FIN 48), effective January 1, 2007. FIN 48 requires a cumulative probability-weighted loss accrual in cases where sustaining a tax position is less than certain. Based on currently available information, we believe it is remote that future costs related to known contingent liability exposures will exceed current accruals by an amount that would have a material adverse impact on our consolidated financial statements.

Environmental

We are subject to the same numerous international, federal, state and local environmental laws and regulations as other companies in the petroleum exploration and production, refining and crude oil and refined product marketing and transportation businesses. The most significant of these environmental laws and regulations include, among others, the:

- U.S. Federal Clean Air Act, which governs air emissions.
- U.S. Federal Clean Water Act, which governs discharges to water bodies.
- European Union Regulation for Registration, Evaluation, Authorization and Restriction of Chemicals (REACH).
- U.S. Federal Comprehensive Environmental Response, Compensation and Liability Act (CERCLA), which imposes liability on generators, transporters and arrangers of hazardous substances at sites where hazardous substance releases have occurred or are threatening to occur.
- U.S. Federal Resource Conservation and Recovery Act (RCRA), which governs the treatment, storage and disposal of solid waste.
- U.S. Federal Oil Pollution Act of 1990 (OPA90), under which owners and operators of onshore facilities and pipelines, lessees or permittees of an area in which an offshore facility is located, and owners and operators of vessels are liable for removal costs and damages that result from a discharge of oil into navigable waters of the United States.
- U.S. Federal Emergency Planning and Community Right-to-Know Act (EPCRA), which requires facilities to report toxic chemical inventories with local emergency planning committees and response departments.
- U.S. Federal Safe Drinking Water Act, which governs the disposal of wastewater in underground injection wells.
- U.S. Department of the Interior regulations, which relate to offshore oil and gas operations in U.S. waters and impose liability for the cost of pollution cleanup resulting from operations, as well as potential liability for pollution damages.
- European Union Trading Directive resulting in European Emissions Trading Scheme.

These laws and their implementing regulations set limits on emissions and, in the case of discharges to water, establish water quality limits. They also, in most cases, require permits in association with new or modified operations. These permits can require an applicant to collect substantial information in connection with the application process, which can be expensive and time-consuming. In addition, there can be delays associated with notice and comment periods and the agency's processing of the application. Many of the delays associated with the permitting process are beyond the control of the applicant.

Many states and foreign countries where we operate also have, or are developing, similar environmental laws and regulations governing these same types of activities. While similar, in some cases these regulations may impose additional, or more stringent, requirements that can add to the cost and difficulty of marketing or transporting products across state and international borders.

The ultimate financial impact arising from environmental laws and regulations is neither clearly known nor easily determinable as new standards, such as air emission standards, water quality standards and stricter fuel regulations continue to evolve. However, environmental laws and regulations, including those that may arise to address concerns about global climate change, are expected to continue to have an increasing impact on our operations in the United States and in other countries in which we operate. Notable areas of potential impacts include air emission compliance and remediation obligations in the United States.

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

We also are subject to certain laws and regulations relating to environmental remediation obligations associated with current and past operations. Such laws and regulations include CERCLA and RCRA and their state equivalents. Remediation obligations include cleanup responsibility arising from petroleum releases from underground storage tanks located at numerous past and present ConocoPhillips-owned and/or operated petroleum-

marketing outlets throughout the United States. Federal and state laws require contamination caused by such underground storage tank releases be assessed and remediated to meet applicable standards. In addition to other cleanup standards, many states adopted cleanup criteria for methyl tertiary-butyl ether (MTBE) for both soil and groundwater.

At RCRA permitted facilities, we are required to assess environmental conditions. If conditions warrant, we may be required to remediate contamination caused by prior operations. In contrast to CERCLA, which is often referred to as "Superfund," the cost of corrective action activities under RCRA corrective action programs typically is borne solely by us. Over the next decade, we anticipate increasing expenditures for RCRA remediation activities may be required, but such annual expenditures for the near term are not expected to vary significantly from the range of such expenditures we have experienced over the past few years. Longer-term expenditures are subject to considerable uncertainty and may fluctuate significantly.

We, from time to time, receive requests for information or notices of potential liability from the EPA and state environmental agencies alleging that we are a potentially responsible party under CERCLA or an equivalent state statute. On occasion, we also have been made a party to cost recovery litigation by those agencies or by private parties. These requests, notices and lawsuits assert potential liability for remediation costs at various sites that typically are not owned by us, but allegedly contain wastes attributable to our past operations. As of December 31, 2007, we reported we had been notified of potential liability under CERCLA and comparable state laws at 68 sites around the United States. At December 31, 2008, we re-opened three sites and closed one of those sites, resolved and closed seven sites, and received two new notices of potential liability, leaving 65 unresolved sites where we have been notified of potential liability.

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

Expensed environmental costs were $957 million in 2008 and are expected to be about $1.0 billion per year in 2009 and 2010. Capitalized environmental costs were $1,025 million in 2008 and are expected to be about $900 million per year in 2009 and 2010.

We accrue for remediation activities when it is probable that a liability has been incurred and reasonable estimates of the liability can be made. These accrued liabilities are not reduced for potential recoveries from insurers or other third parties and are not discounted (except those assumed in a purchase business combination, which we do record on a discounted basis).

Many of these liabilities result from CERCLA, RCRA and similar state laws that require us to undertake certain investigative and remedial activities at sites where we conduct, or once conducted, operations or at sites where ConocoPhillips-generated waste was disposed. The accrual also includes a number of sites we identified that may require environmental remediation, but which are not currently the subject of CERCLA, RCRA or state enforcement activities. If applicable, we accrue receivables for probable insurance or other third-party recoveries. In the future, we may incur significant costs under both CERCLA and RCRA. Considerable uncertainty exists with respect to these costs, and under adverse changes in circumstances, potential liability may exceed amounts accrued as of December 31, 2008.

Remediation activities vary substantially in duration and cost from site to site, depending on the mix of unique site characteristics, evolving remediation technologies, diverse regulatory agencies and enforcement policies, and the presence or absence of potentially liable third parties. Therefore, it is difficult to develop reasonable estimates of future site remediation costs.

At December 31, 2008, our balance sheet included total accrued environmental costs of $979 million, compared with $1,089 million at December 31, 2007. We expect to incur a substantial amount of these expenditures within the next 30 years.

Notwithstanding any of the foregoing, and as with other companies engaged in similar businesses, environmental costs and liabilities are inherent in our operations and products, and there can be no assurance that material costs and liabilities will not be incurred. However, we currently do not expect any material adverse effect upon our results of operations or financial position as a result of compliance with current environmental laws and regulations.

Climate Change

There has been a broad range of proposed or promulgated state, national and international laws focusing on greenhouse gas (GHG) reduction. These proposed or promulgated laws apply or could apply in countries where we have interests or may have interests in the future. Laws in this field continue to evolve, and while they are likely to be increasingly widespread and stringent, at this stage it is not possible to accurately estimate either a timetable for implementation or our future compliance costs relating to implementation. Compliance with changes in laws, regulations and obligations that create a GHG emissions trading scheme or GHG reduction policies generally could significantly

increase costs or reduce demand for fossil energy derived products. Examples of legislation or precursors for possible regulation that does or could affect our operations include:

- European Emissions Trading Scheme (ETS), the program through which many of the European Union (EU) member states are implementing the Kyoto Protocol.
- California's Global Warming Solutions Act, which requires the California Air Resources Board (CARB) to develop regulations and market mechanisms that will ultimately reduce California's greenhouse gas emissions by 25 percent by 2020.
- Two regulations issued by the Alberta government in 2007 under the Climate Change and Emissions Act. These regulations require any existing facility with emissions equal to or greater than 100,000 metric tons of carbon dioxide or equivalent per year to reduce the net emissions intensity of that facility by 2 percent per year beginning July 1, 2007, with an ultimate reduction target of 12 percent of baseline emissions.
- The U.S. Supreme Court decision in Massachusetts v. EPA, 549 U.S. 497, 127 S.Ct. 1438 (2007) confirming that the U.S. Environmental Protection Agency (EPA) has the authority to regulate carbon dioxide as an "air pollutant" under the Federal Clean Air Act.

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

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

Other

We have deferred tax assets related to certain accrued liabilities, loss carryforwards and credit carryforwards. Valuation allowances have been established to reduce these deferred tax assets to an amount that will, more likely than not, be realized. Based on our historical taxable income, our expectations for the future, and available tax-planning strategies, management expects that the net deferred tax assets will be realized as offsets to reversing deferred tax liabilities and as reductions in future taxable income.

New Accounting Standards

In December 2007, the FASB issued Statement of Financial Accounting Standards (SFAS) No. 141 (Revised), "Business Combinations" (SFAS No. 141(R)). This Statement will apply to all transactions in which an entity obtains control of one or more other businesses. In general, SFAS No. 141(R) requires the acquiring entity in a business combination to recognize the fair value of all the assets acquired and liabilities assumed in the transaction; establishes the acquisition date as the fair value measurement point; and modifies the disclosure requirements. Additionally, it changes the accounting treatment for transaction costs, acquired contingent arrangements, in-process research and development, restructuring costs, changes in deferred tax asset valuation allowances as a result of business combination, and changes in income tax uncertainties after the acquisition date. This Statement applies prospectively to business combinations for which the acquisition date is on or after January 1, 2009. However, starting January 1, 2009, accounting for changes in valuation allowances for acquired deferred tax assets and the resolution of uncertain tax positions for prior business combinations will impact tax expense instead of impacting goodwill.

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

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

In November 2008, the FASB reached a consensus on Emerging Issues Task Force Issue No. 08-6, "Equity Method Investment Accounting Considerations" (EITF 08-6), which was issued to clarify how the application of equity method accounting will be affected by SFAS No. 141(R) and SFAS No. 160. EITF 08-6 clarifies that an entity shall continue to use the cost accumulation model for its equity method investments. It also confirms past accounting practices related to the treatment of

contingent consideration and the use of the impairment model under Accounting Principles Board (APB) Opinion No. 18, "The Equity Method of Accounting for Investments in Common Stock." Additionally, it requires an equity method investor to account for a share issuance by an investee as if the investor had sold a proportionate share of the investment. This issue is effective January 1, 2009, and will be applied prospectively.

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

Critical Accounting Estimates

The preparation of financial statements in conformity with generally accepted accounting principles requires management to select appropriate accounting policies and to make estimates and assumptions that affect the reported amounts of assets, liabilities, revenues and expenses. See Note 1 — Accounting Policies, in the Notes to Consolidated Financial Statements, for descriptions of our major accounting policies. Certain of these accounting policies involve judgments and uncertainties to such an extent that there is a reasonable likelihood that materially different amounts would have been reported under different conditions, or if different assumptions had been used. These critical accounting estimates are discussed with the Audit and Finance Committee of the Board of Directors at least annually. We believe the following discussions of critical accounting estimates, along with the discussions of contingencies and of deferred tax asset valuation allowances in this report, address all important accounting areas where the nature of accounting estimates or assumptions is material due to the levels of subjectivity and judgment necessary to account for highly uncertain matters or the susceptibility of such matters to change.

Oil and Gas Accounting

Accounting for oil and gas exploratory activity is subject to special accounting rules unique to the oil and gas industry. The acquisition of geological and geophysical seismic information, prior to the discovery of proved reserves, is expensed as incurred, similar to accounting for research and development costs. However, leasehold acquisition costs and exploratory well costs are capitalized on the balance sheet pending determination of whether proved oil and gas reserves have been discovered on the prospect.

Property Acquisition Costs

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

This judgmental probability percentage is reassessed and adjusted throughout the contractual period of the leasehold based on favorable or unfavorable exploratory activity on the leasehold or on adjacent leaseholds, and leasehold impairment amortization expense is adjusted prospectively. At year-end 2008, the book value of the pools of property acquisition costs, that individually are relatively small and thus subject to the above-described periodic leasehold impairment calculation, was $1,447 million and the accumulated impairment reserve was $494 million. The weighted-average judgmental percentage probability of ultimate failure was approximately 65 percent, and the weighted-average amortization period was approximately 2.4 years. If that judgmental percentage were to be raised by 5 percent across all calculations, pretax leasehold impairment expense in 2009 would increase by approximately $30 million. The remaining $4,745 million of capitalized unproved property costs at year-end 2008 consisted of individually significant leaseholds, mineral rights held in perpetuity by title ownership, exploratory wells currently drilling, and suspended exploratory wells. Management periodically assesses individually significant leaseholds for impairment based on the results of exploration and drilling efforts and the outlook for project commercialization. Of this amount, approximately $2.4 billion is concentrated in 10 major development areas. None of these major assets are expected to move to proved properties in 2009.

Exploratory Costs

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

Once a determination is made the well did not encounter potentially economic oil and gas quantities, the well costs are expensed as a dry hole and reported in exploration expense. If exploratory wells encounter potentially economic quantities of oil and gas, the well costs remain capitalized on the balance sheet as long as sufficient progress assessing the reserves and the economic and operating viability of the project is being made. The accounting notion of "sufficient progress" is a judgmental area, but the accounting rules do prohibit continued capitalization of suspended well costs on the mere chance that future market conditions will improve or new technologies will be found that would make the project's development economically profitable. Often, the ability to move the project into the development phase and record proved reserves is dependent on obtaining permits and government or co-venturer approvals, the timing of which is ultimately beyond our control. Exploratory well costs remain suspended as long as the company is actively pursuing such approvals and permits, and believes they will be obtained. Once all required approvals and permits have been obtained, the projects are moved into the development phase, and the oil and gas reserves are designated as proved

reserves. For complex exploratory discoveries, it is not unusual to have exploratory wells remain suspended on the balance sheet for several years while we perform additional appraisal drilling and seismic work on the potential oil and gas field, or while we seek government or co-venturer approval of development plans or seek environmental permitting.

Management reviews suspended well balances quarterly, continuously monitors the results of the additional appraisal drilling and seismic work, and expenses the suspended well costs as a dry hole when it determines the potential field does not warrant further investment in the near term. Criteria utilized in making this determination include evaluation of the reservoir characteristics and hydrocarbon properties, expected development costs, ability to apply existing technology to produce the reserves, fiscal terms, regulations or contract negotiations, and our required return on investment.

At year-end 2008, total suspended well costs were $660 million, compared with $589 million at year-end 2007. For additional information on suspended wells, including an aging analysis, see Note 8 — Properties, Plants and Equipment, in the Notes to Consolidated Financial Statements.

Proved Oil and Gas Reserves and Canadian Syncrude Reserves

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

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

Proved reserve estimates are updated annually and take into account recent production and subsurface information about each field or oil sand mining operation. Also, as required by current authoritative guidelines, the estimated future date when a field or oil sand mining operation will be permanently shut down for economic reasons is based on an extrapolation of sales prices and operating costs prevalent at the balance sheet date. This estimated date when production will end affects the amount of estimated reserves. Therefore, as prices and cost levels change from year to year, the estimate of proved reserves also changes.

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

The estimation of proved reserves also is important to the statement of operations because the proved oil and gas reserve estimate for a field or the estimated in-place crude bitumen volume for an oil sand mining operation serves as the denominator in the unit-of-production calculation of depreciation, depletion and amortization of the capitalized costs for that asset. At year-end 2008, the net book value of productive E&P properties, plants and equipment subject to a unit-of-production calculation, including our Canadian Syncrude bitumen oil sand assets, was approximately $58 billion and the depreciation, depletion and amortization recorded on these assets in 2008 was approximately $7.7 billion. The estimated proved developed oil and gas reserves of these fields were 6.1 billion BOE at the beginning of 2008 and were 5.5 billion BOE at the end of 2008. The estimated proved reserves of Canadian Syncrude assets were 221 million barrels at the beginning of 2008 and were 249 million barrels at the end of 2008. If the estimates of proved reserves used in the unit-of-production calculations had been lower by 5 percent across all calculations, pretax depreciation, depletion and amortization in 2008 would have increased by an estimated $406 million. Impairments of producing oil and gas properties in 2008, 2007 and 2006 totaled $793 million, $471 million and $215 million, respectively. Of these write-downs, $56 million in 2008, $76 million in 2007 and $131 million in 2006 were due to downward revisions of proved reserves due to reservoir performance.

Impairments

Long-lived assets used in operations are assessed for impairment whenever changes in facts and circumstances indicate a possible significant deterioration in the future cash flows expected to be generated by an asset group. If, upon review, the sum of the undiscounted pretax cash flows is less than the carrying value of the asset group, the carrying value is written down to estimated fair value. Individual assets are grouped for impairment purposes based on a judgmental assessment of the lowest level for which there are identifiable cash flows that are largely independent of the cash flows of other groups of assets — generally on a field-by-field basis for exploration and production assets, at an entire complex level for downstream assets, or at a site level for retail stores. Because there usually is a lack of quoted market prices for long-lived assets, the fair value of impaired assets is determined based on the present values of expected future cash flows using discount rates commensurate with the risks involved in the asset group or based on a multiple of operating cash flow validated with historical market transactions of similar assets where possible. The expected future cash flows used for impairment reviews and related fair value calculations are

based on judgmental assessments of future production volumes, prices and costs, considering all available information at the date of review. See Note 10 — Impairments, in the Notes to Consolidated Financial Statements, for additional information.

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

Asset Retirement Obligations and Environmental Costs

Under various contracts, permits and regulations, we have material legal obligations to remove tangible equipment and restore the land or seabed at the end of operations at operational sites. Our largest asset removal obligations involve removal and disposal of offshore oil and gas platforms around the world, oil and gas production facilities and pipelines in Alaska, and asbestos abatement at refineries. The fair values of obligations for dismantling and removing these facilities are accrued at the installation of the asset based on estimated discounted costs. Estimating the future asset removal costs necessary for this accounting calculation is difficult. Most of these removal obligations are many years, or decades, in the future and the contracts and regulations often have vague descriptions of what removal practices and criteria must be met when the removal event actually occurs. Asset removal technologies and costs are changing constantly, as well as political, environmental, safety and public relations considerations.

In addition, under the above or similar contracts, permits and regulations, we have certain obligations to complete environmental-related projects. These projects are primarily related to cleanup at domestic refineries and underground storage tanks at U.S. service stations, and remediation activities required by Canada and the state of Alaska at exploration and production sites. Future environmental remediation costs are difficult to estimate because they are subject to change due to such factors as the uncertain magnitude of cleanup costs, the unknown time and extent of such remedial actions that may be required, and the determination of our liability in proportion to that of other responsible parties.

Business Acquisitions

Purchase Price Allocation

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

Intangible Assets and Goodwill

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

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

Projected Benefit Obligations

Determination of the projected benefit obligations for our defined benefit pension and postretirement plans are important to the recorded amounts for such obligations on the balance sheet and to the amount of benefit expense in the statement of operations. The actuarial determination of projected benefit obligations and company contribution requirements involves judgment about uncertain future events, including estimated retirement dates, salary levels at retirement, mortality rates, lump-sum election rates, rates of return on plan assets, future health care cost-trend rates, and rates of utilization of health care services by retirees. Due to the specialized nature of these calculations, we engage outside actuarial firms to assist in the determination of these projected benefit obligations and company contribution requirements. For Employee Retirement Income Security Act-qualified pension plans, the actuary exercises fiduciary care on behalf of plan participants in the determination of the judgmental assumptions used in determining required company contributions into plan assets. Due to differing objectives and requirements between financial

accounting rules and the pension plan funding regulations promulgated by governmental agencies, the actuarial methods and assumptions for the two purposes differ in certain important respects. Ultimately, we will be required to fund all promised benefits under pension and postretirement benefit plans not funded by plan assets or investment returns, but the judgmental assumptions used in the actuarial calculations significantly affect periodic financial statements and funding patterns over time. Benefit expense is particularly sensitive to the discount rate and return on plan assets assumptions. A 1 percent decrease in the discount rate would increase annual benefit expense by $79 million, while a 1 percent decrease in the return on plan assets assumption would increase annual benefit expense by $43 million. In determining the discount rate, we use yields on high-quality fixed income investments matched to the estimated benefit cash flows of our plans.

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

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

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

- Fluctuations in crude oil, natural gas and natural gas liquids prices, refining and marketing margins and margins for our chemicals business.
- Potential failure or delays in achieving expected reserve or production levels from existing and future oil and gas development projects due to operating hazards, drilling risks and the inherent uncertainties in predicting oil and gas reserves and oil and gas reservoir performance.
- Unsuccessful exploratory drilling activities or the inability to obtain access to exploratory acreage.
- Failure of new products and services to achieve market acceptance.
- Unexpected changes in costs or technical requirements for constructing, modifying or operating facilities for exploration and production, manufacturing, refining or transportation projects.
- Unexpected technological or commercial difficulties in manufacturing, refining, or transporting our products, including synthetic crude oil and chemicals products.
- Lack of, or disruptions in, adequate and reliable transportation for our crude oil, natural gas, natural gas liquids, LNG and refined products.
- Inability to timely obtain or maintain permits, including those necessary for construction of LNG terminals or regasification facilities, or refinery projects; comply with government regulations; or make capital expenditures required to maintain compliance.
- Failure to complete definitive agreements and feasibility studies for, and to timely complete construction of, announced and future exploration and production, LNG, refinery and transportation projects.
- Potential disruption or interruption of our operations due to accidents, extraordinary weather events, civil unrest, political events or terrorism.
- International monetary conditions and exchange controls.
- Substantial investment or reduced demand for products as a result of existing or future environmental rules and regulations.
- Liability for remedial actions, including removal and reclamation obligations, under environmental regulations.
- Liability resulting from litigation.
- General domestic and international economic and political developments, including: armed hostilities; expropriation of assets; changes in governmental policies relating to crude oil, natural gas, natural gas liquids or refined product pricing, regulation, or taxation; other political, economic or diplomatic developments; and international monetary fluctuations.
- Changes in tax and other laws, regulations (including alternative energy mandates), or royalty rules applicable to our business.
- Limited access to capital or significantly higher cost of capital related to illiquidity or uncertainty in the domestic or international financial markets.
- Inability to obtain economical financing for projects, construction or modification of facilities and general corporate purposes.
- The operation and financing of our midstream and chemicals joint ventures.
- The factors generally described in the "Risk Factors" section included as Item 1A in our 2008 Annual Report on Form 10-K.

Quantitative and Qualitative Disclosures About Market Risk

Financial Instrument Market Risk

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

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

Commodity Price Risk

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

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

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

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

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

Interest Rate Risk

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

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

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

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

Foreign Currency Risk

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

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

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

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

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

Selected Financial Data

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

See Management's Discussion and Analysis of Financial Condition and Results of Operations for a discussion of factors that will enhance an understanding of this data.

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

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

Additionally, the acquisition of Burlington Resources in 2006 affects the comparability of the amounts included in the table above. See Note 3 — Acquisition of Burlington Resources Inc., in the Notes to Consolidated Financial Statements, for additional information. See Note 2 — Changes in Accounting Principles, in the Notes to Consolidated Financial Statements, for information on changes in accounting principles affecting the comparability of amounts included in the table above.

Selected Quarterly Financial Data

	Millions of Dollars			Per Share of Common Stock	
				Net Income (Loss)	
	Sales and Other Operating Revenues*	Income (Loss) Before Income Taxes	Net Income (Loss)	Basic	Diluted
2008					
First	**$54,883**	**7,549**	**4,139**	**2.65**	**2.62**
Second	**71,411**	**9,795**	**5,439**	**3.54**	**3.50**
Third	**70,044**	**9,467**	**5,188**	**3.43**	**3.39**
Fourth**	**44,504**	**(30,404)**	**(31,764)**	**(21.37)**	**(21.37)**
2007					
First	$41,320	6,066	3,546	2.15	2.12
Second***	47,370	3,518	301	.18	.18
Third	46,062	6,364	3,673	2.26	2.23
Fourth	52,685	7,324	4,371	2.75	2.71

**Includes excise taxes on petroleum products sales.*

***Includes noncash impairments relating to goodwill and to our LUKOIL investment that together amount to $32,853 million before- and after-tax.*

****Includes noncash impairment charge of $4,588 million before-tax, $4,512 million after-tax, for the expropriation of our Venezuelan oil interests.*

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

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

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

Report of Management

Management prepared, and is responsible for, the consolidated financial statements and the other information appearing in this annual report. The consolidated financial statements present fairly the company's financial position, results of operations and cash flows in conformity with accounting principles generally accepted in the United States. In preparing its consolidated financial statements, the company includes amounts that are based on estimates and judgments that management believes are reasonable under the circumstances. The company's financial statements have been audited by Ernst & Young LLP, an independent registered public accounting firm appointed by the Audit and Finance Committee of the Board of Directors and ratified by stockholders. Management has made available to Ernst & Young LLP all of the company's financial records and related data, as well as the minutes of stockholders' and directors' meetings.

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

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

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

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

James J. Mulva
Chairman and
Chief Executive Officer

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

February 25, 2009

Report of Independent Registered Public Accounting Firm on Consolidated Financial Statements

The Board of Directors and Stockholders
ConocoPhillips

We have audited the accompanying consolidated balance sheets of ConocoPhillips as of December 31, 2008 and 2007, and the related consolidated statements of operations, changes in common stockholders' equity, and cash flows for each of the three years in the period ended December 31, 2008. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audits.

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

In our opinion, the financial statements referred to above present fairly, in all material respects, the consolidated financial position of ConocoPhillips at December 31, 2008 and 2007, and the consolidated results of its operations and its cash flows for each of the three years in the period ended December 31, 2008, in conformity with U.S. generally accepted accounting principles.

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

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

Ernst & Young LLP

Houston, Texas
February 25, 2009

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

The Board of Directors and Stockholders
ConocoPhillips

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

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

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

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

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

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

Houston, Texas
February 25, 2009

Consolidated Statement of Operations

ConocoPhillips

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

***Includes allocated goodwill.*

See Notes to Consolidated Financial Statements.

Consolidated Balance Sheet

ConocoPhillips

At December 31	Millions of Dollars	
	2008	2007
Assets		
Cash and cash equivalents	**$ 755**	1,456
Accounts and notes receivable (net of allowance of $61 million in 2008 and $58 million in 2007)	**10,892**	14,687
Accounts and notes receivable — related parties	**1,103**	1,667
Inventories	**5,095**	4,223
Prepaid expenses and other current assets	**2,998**	2,702
Total Current Assets	**20,843**	24,735
Investments and long-term receivables	**30,926**	31,457
Loans and advances — related parties	**1,973**	1,871
Net properties, plants and equipment	**83,947**	89,003
Goodwill	**3,778**	29,336
Intangibles	**846**	896
Other assets	**552**	459
Total Assets	**$142,865**	177,757
Liabilities		
Accounts payable	**$ 12,852**	16,591
Accounts payable — related parties	**1,138**	1,270
Short-term debt	**370**	1,398
Accrued income and other taxes	**4,273**	4,814
Employee benefit obligations	**939**	920
Other accruals	**2,208**	1,889
Total Current Liabilities	**21,780**	26,882
Long-term debt	**27,085**	20,289
Asset retirement obligations and accrued environmental costs	**7,163**	7,261
Joint venture acquisition obligation — related party	**5,669**	6,294
Deferred income taxes	**18,167**	21,018
Employee benefit obligations	**4,127**	3,191
Other liabilities and deferred credits	**2,609**	2,666
Total Liabilities	**86,600**	87,601
Minority Interests	**1,100**	1,173
Common Stockholders' Equity		
Common stock (2,500,000,000 shares authorized at $.01 par value)		
Issued (2008 — 1,729,264,859 shares; 2007 — 1,718,448,829 shares)		
Par value	**17**	17
Capital in excess of par	**43,396**	42,724
Grantor trusts (at cost: 2008 — 40,739,129 shares; 2007 — 42,411,331 shares)	**(702)**	(731)
Treasury stock (at cost: 2008 — 208,346,815 shares; 2007 — 104,607,149 shares)	**(16,211)**	(7,969)
Accumulated other comprehensive income (loss)	**(1,875)**	4,560
Unearned employee compensation	**(102)**	(128)
Retained earnings	**30,642**	50,510
Total Common Stockholders' Equity	**55,165**	88,983
Total	**$142,865**	177,757

See Notes to Consolidated Financial Statements.

Consolidated Statement of Cash Flows

ConocoPhillips

Years Ended December 31	Millions of Dollars		
	2008	2007*	2006*
Cash Flows From Operating Activities			
Net income (loss)	**$ (16,998)**	11,891	15,550
Adjustments to reconcile net income (loss) to net cash provided by operating activities			
Depreciation, depletion and amortization	**9,012**	8,298	7,284
Impairments	**34,539**	5,030	683
Dry hole costs and leasehold impairments	**698**	463	351
Accretion on discounted liabilities	**418**	341	281
Deferred taxes	**(428)**	(33)	184
Undistributed equity earnings	**(1,609)**	(1,823)	(945)
Gain on asset dispositions	**(891)**	(1,348)	(116)
Other	**(1,064)**	176	(74)
Working capital adjustments**			
Decrease (increase) in accounts and notes receivable	**4,225**	(2,492)	(906)
Decrease (increase) in inventories	**(1,321)**	767	(829)
Decrease (increase) in prepaid expenses and other current assets	**(724)**	487	(372)
Increase (decrease) in accounts payable	**(3,874)**	2,772	657
Increase (decrease) in taxes and other accruals	**675**	21	(232)
Net Cash Provided by Operating Activities	**22,658**	24,550	21,516
Cash Flows From Investing Activities			
Capital expenditures and investments***	**(19,099)**	(11,791)	(15,596)
Acquisition of Burlington Resources Inc.***	**—**	—	(14,285)
Proceeds from asset dispositions	**1,640**	3,572	545
Long-term advances/loans — related parties	**(163)**	(682)	(780)
Collection of advances/loans — related parties	**34**	89	123
Other	**(28)**	250	—
Net Cash Used in Investing Activities	**(17,616)**	(8,562)	(29,993)
Cash Flows From Financing Activities			
Issuance of debt	**7,657**	935	17,314
Repayment of debt	**(1,897)**	(6,454)	(7,082)
Issuance of company common stock	**198**	285	220
Repurchase of company common stock	**(8,249)**	(7,001)	(925)
Dividends paid on company common stock	**(2,854)**	(2,661)	(2,277)
Other	**(619)**	(444)	(185)
Net Cash Provided by (Used in) Financing Activities	**(5,764)**	(15,340)	7,065
Effect of Exchange Rate Changes on Cash and Cash Equivalents	**21**	(9)	15
Net Change in Cash and Cash Equivalents	**(701)**	639	(1,397)
Cash and cash equivalents at beginning of year	**1,456**	817	2,214
Cash and Cash Equivalents at End of Year	**$ 755**	1,456	817

**Certain amounts were reclassified to conform to 2008 presentation.*
***Net of acquisition and disposition of businesses.*
****Net of cash acquired.*
See Notes to Consolidated Financial Statements.

Consolidated Statement of Changes in Common Stockholders' Equity

	Shares of Common Stock			Millions of Dollars							
				Common Stock				Accumulated			
	Issued	Held in Treasury	Held in Grantor Trusts	Par Value	Capital in Excess of Par	Treasury Stock	Grantor Trusts	Other Comprehensive Income (Loss)	Unearned Employee Compensation	Retained Earnings	Total
December 31, 2005	1,455,861,340	32,080,000	45,932,093	$14	26,754	(1,924)	(778)	814	(167)	28,018	52,731
Net income										15,550	15,550
Other comprehensive income											
Minimum pension liability adjustment								33			33
Foreign currency translation adjustments								1,013			1,013
Hedging activities								4			4
Comprehensive income											16,600
Initial application of SFAS No. 158								(575)			(575)
Cash dividends paid on company common stock										(2,277)	(2,277)
Burlington Resources acquisition	239,733,571	(32,080,000)	890,180	3	14,475	1,924	(53)				16,349
Repurchase of company common stock		15,061,613	(542,000)			(964)	32				(932)
Distributed under incentive compensation and other benefit plans	9,907,698		(1,921,688)		697		33				730
Recognition of unearned compensation									19		19
Other										1	1
December 31, 2006	1,705,502,609	15,061,613	44,358,585	17	41,926	(964)	(766)	1,289	(148)	41,292	82,646
Net income										11,891	11,891
Other comprehensive income (loss)											
Defined benefit pension plans:											
Net prior service cost								63			63
Net gain								213			213
Nonsponsored plans								(2)			(2)
Foreign currency translation adjustments								3,075			3,075
Hedging activities								(4)			(4)
Comprehensive income											15,236
Initial application of SFAS No. 158 — equity affiliate								(74)			(74)
Cash dividends paid on company common stock										(2,661)	(2,661)
Repurchase of company common stock		89,545,536	(177,110)			(7,005)	11				(6,994)
Distributed under incentive compensation and other benefit plans	12,946,220		(1,856,224)		798		31				829
Recognition of unearned compensation									20		20
Other			86,080				(7)			(12)	(19)
December 31, 2007	1,718,448,829	104,607,149	42,411,331	17	42,724	(7,969)	(731)	4,560	(128)	50,510	88,983
Net loss										**(16,998)**	**(16,998)**
Other comprehensive income (loss)											
Defined benefit pension plans:											
Net prior service cost								**22**			**22**
Net loss								**(950)**			**(950)**
Nonsponsored plans								**(41)**			**(41)**
Foreign currency translation adjustments								**(5,464)**			**(5,464)**
Hedging activities								**(2)**			**(2)**
Comprehensive loss											**(23,433)**
Cash dividends paid on company common stock										**(2,854)**	**(2,854)**
Repurchase of company common stock		**103,739,666**	**(13,600)**			**(8,242)**	**1**				**(8,241)**
Distributed under incentive compensation and other benefit plans	**10,816,030**		**(1,668,456)**		**672**		**28**				**700**
Recognition of unearned compensation									**26**		**26**
Other			**9,854**							**(16)**	**(16)**
December 31, 2008	**1,729,264,859**	**208,346,815**	**40,739,129**	**$17**	**43,396**	**(16,211)**	**(702)**	**(1,875)**	**(102)**	**30,642**	**55,165**

See Notes to Consolidated Financial Statements.

Notes to Consolidated Financial Statements

Note 1 — Accounting Policies

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

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

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

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

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

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

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

- **Shipping and Handling Costs —** Our Exploration and Production (E&P) segment includes shipping and handling costs in production and operating expenses for production activities. Transportation costs related to E&P marketing activities are recorded in purchased crude oil, natural gas and products. The Refining and Marketing (R&M) segment records shipping and handling costs in purchased crude oil, natural gas and products. Freight costs billed to customers are recorded as a component of revenue.

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

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

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

  Recognition and classification of the gain or loss that results from recording and adjusting a derivative to fair value depends on the purpose for issuing or holding the derivative. Gains and losses from derivatives that are not accounted for as hedges under Statement of Financial Accounting Standards (SFAS) No. 133, "Accounting for Derivative Instruments and Hedging Activities," are recognized immediately in earnings. For

derivative instruments that are designated and qualify as a fair value hedge, the gains or losses from adjusting the derivative to its fair value will be immediately recognized in earnings and, to the extent the hedge is effective, offset the concurrent recognition of changes in the fair value of the hedged item. Gains or losses from derivative instruments that are designated and qualify as a cash flow hedge or hedge of a net investment in a foreign entity will be recorded on the balance sheet in accumulated other comprehensive income (loss) until the hedged transaction is recognized in earnings; however, to the extent the change in the value of the derivative exceeds the change in the anticipated cash flows of the hedged transaction, the excess gains or losses will be recognized immediately in earnings.

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

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

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

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

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

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

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

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

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

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

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

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

- **Depreciation and Amortization —** Depreciation and amortization of properties, plants and equipment on producing oil and gas properties, certain pipeline assets (those which are expected to have a declining utilization pattern), and on

Syncrude mining operations are determined by the unit-of-production method. Depreciation and amortization of all other properties, plants and equipment are determined by either the individual-unit-straight-line method or the group-straight-line method (for those individual units that are highly integrated with other units).

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

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

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

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

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

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

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

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

- **Guarantees —** The fair value of a guarantee is determined and recorded as a liability at the time the guarantee is given. The initial liability is subsequently reduced as we are released from exposure under the guarantee. We amortize the guarantee liability over the relevant time period, if one exists, based on the facts and circumstances surrounding each type of guarantee. In cases where the guarantee term is indefinite, we reverse the liability when we have information that the liability is essentially relieved or amortize it over an appropriate time period as the fair value of our guarantee exposure declines over time. We amortize the guarantee liability to the related statement of operations line item based on the nature of the guarantee. When it becomes probable that we will have to

perform on a guarantee, we accrue a separate liability if it is reasonably estimable, based on the facts and circumstances at that time. We reverse the fair value liability only when there is no further exposure under the guarantee.

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

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

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

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

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

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

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

Note 2 — Changes in Accounting Principles

SFAS No. 157

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

Due to our election under FSP 157-2, for 2008, SFAS No. 157 applies to commodity and foreign currency derivative contracts and certain nonqualified deferred compensation and retirement plan assets that are measured at fair value on a recurring basis in periods subsequent to initial recognition. The implementation of SFAS No. 157 did not cause a change in the method of calculating fair value of assets or liabilities, with the exception of incorporating the impact of our nonperformance risk on derivative liabilities — which was not material. The primary impact from adoption was additional disclosures.

SFAS No. 157 requires disclosures that categorize assets and liabilities measured at fair value into one of three different levels depending on the observability of the inputs employed in the measurement. Level 1 inputs are quoted prices in active markets for identical assets or liabilities. Level 2 inputs are observable inputs other than quoted prices included within Level 1 for the

asset or liability, either directly or indirectly through market-corroborated inputs. Level 3 inputs are unobservable inputs for the asset or liability reflecting significant modifications to observable related market data or our assumptions about pricing by market participants.

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

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

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

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

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

The derivative values above are based on an analysis of each contract as the fundamental unit of account as required by SFAS No. 157; therefore, derivative assets and liabilities with the same counterparty are not netted where the legal right of offset exists, which is different than the net presentation basis in Note 16 — Financial Instruments and Derivative Contracts. Gains or losses from contracts in one level may be offset by gains or losses on contracts in another level or by changes in values of physical contracts or positions that are not reflected in the table above.

During 2008, the fair value of net commodity derivatives classified as Level 3 in the fair value hierarchy changed as follows:

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

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

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

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

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

SFAS No. 159

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

Other

In December 2008, the FASB issued FSP FAS 140-4 and FIN 46(R)-8, "Disclosures about Transfers of Financial Assets and Interest in Variable Interest Entities." This FSP requires

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

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

In June 2006, the FASB issued Interpretation No. 48, "Accounting for Uncertainty in Income Taxes — an interpretation of FASB Statement No. 109" (FIN 48). This Interpretation provides guidance on recognition, classification and disclosure concerning uncertain tax liabilities. The evaluation of a tax position requires recognition of a tax benefit if it is more likely than not it will be sustained upon examination. We adopted FIN 48 effective January 1, 2007. The adoption did not have a material impact on our consolidated financial statements. See Note 21 — Income Taxes, for additional information about income taxes.

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

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

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

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

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

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

Note 3 — Acquisition of Burlington Resources Inc.

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

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

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

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

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

Note 4 — Variable Interest Entities (VIEs)

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

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

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

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

We have an agreement with Freeport LNG Development, L.P. (Freeport LNG) to participate in a liquefied natural gas (LNG) receiving terminal in Quintana, Texas. We have no ownership in Freeport LNG; however, we obtained a 50 percent interest in Freeport LNG GP, Inc (Freeport GP), which serves as the general partner managing the venture. We entered into a credit agreement with Freeport LNG, whereby we agreed to provide loan financing for the construction of the terminal. We also entered into a long-term agreement with Freeport LNG to use 0.9 billion cubic feet per day of regasification capacity. The terminal became operational in June 2008, and we began making payments under the terminal use agreement. In August 2008, the loan was converted from a construction loan to a term loan and consisted of $650 million in loan financing and $124 million of accrued interest. Freeport LNG began making loan repayments in September 2008 and the loan balance outstanding as of December 31, 2008, was $757 million. Freeport LNG is a VIE because Freeport GP holds no equity in Freeport LNG and the limited partners of Freeport LNG do not have any substantive decision making ability. We performed an analysis of the expected losses and determined we are not the primary beneficiary. This expected loss analysis took into account that the credit support arrangement requires Freeport LNG to maintain sufficient commercial insurance to mitigate any loan losses. The loan to Freeport LNG is accounted for as a financial asset, and our investment in Freeport GP is accounted for as an equity investment.

In the case of Ashford Energy Capital S.A., we consolidate this entity in our financial statements because we are the primary beneficiary of this VIE based on an analysis of the variability of the expected losses and expected residual returns. In December 2001, in order to raise funds for general corporate purposes, ConocoPhillips and Cold Spring Finance S.a.r.l. formed Ashford through the contribution of a $1 billion ConocoPhillips subsidiary promissory note and $500 million cash by Cold Spring. Through its initial $500 million investment, Cold Spring is entitled to a cumulative annual preferred return consisting of 1.32 percent plus a three-month LIBOR rate set at the beginning of each quarter. The preferred return at December 31, 2008, was 5.37 percent. In 2008, Cold Spring declined its option to remarket its investment in Ashford. This option remains available in 2018 and at each 10-year anniversary thereafter. If remarketing is unsuccessful, we could be required to provide a letter of credit in support of Cold Spring's investment, or in the event such a letter of credit is not provided, cause the redemption

of Cold Spring's investment in Ashford. Should our credit rating fall below investment grade, Ashford would require a letter of credit to support $475 million of the term loans, as of December 31, 2008, made by Ashford to other ConocoPhillips subsidiaries. If the letter of credit is not obtained within 60 days, Cold Spring could cause Ashford to sell the ConocoPhillips subsidiary notes. At December 31, 2008, Ashford held $2.0 billion of ConocoPhillips subsidiary notes and $28 million in investments unrelated to ConocoPhillips. We report Cold Spring's investment as a minority interest because it is not mandatorily redeemable, and the entity does not have a specified liquidation date. Other than the obligation to make payment on the subsidiary notes described above, Cold Spring does not have recourse to our general credit.

Note 5 — Inventories

Inventories at December 31 were:

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

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

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

Note 6 — Assets Held for Sale

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

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

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

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

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

Note 7 — Investments, Loans and Long-Term Receivables

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

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

Equity Investments

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

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

- FCCL Oil Sands Partnership — 50 percent owned business venture with EnCana Corporation — produces heavy oil in the Athabasca oil sands in northeastern Alberta, as well as transports and sells the bitumen blend.
- WRB Refining LLC — 50 percent owned business venture with EnCana Corporation — processes crude oil at the Wood River and Borger refineries, as well as purchases and transports all feedstocks for the refineries and sells the refined products.
- OAO LUKOIL — 20 percent ownership interest. LUKOIL explores for and produces crude oil, natural gas and natural gas liquids; refines, markets and transports crude oil and petroleum products; and is headquartered in Russia.
- OOO Naryanmarneftegaz (NMNG) — 30 percent ownership interest and a 50 percent governance interest — a joint venture with LUKOIL to explore for, develop and produce oil and gas resources in the northern part of Russia's Timan-Pechora province.
- DCP Midstream, LLC — 50 percent owned joint venture with Spectra Energy — owns and operates gas plants, gathering systems, storage facilities and fractionation plants.
- Chevron Phillips Chemical Company LLC (CPChem) — 50 percent owned joint venture with Chevron Corporation — manufactures and markets petrochemicals and plastics.

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

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

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

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

Australia Pacific LNG

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

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

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

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

FCCL and WRB

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

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

WRB's operating assets consist of the Wood River and Borger refineries, located in Roxana, Illinois, and Borger, Texas, respectively. As a result of our contribution of these two assets to WRB, a basis difference of $5 billion was created due to the fair value of the contributed assets recorded by WRB exceeding their historical book value. The difference is primarily amortized and recognized as a benefit evenly over a period of 25 years, which is the estimated remaining useful life of the refineries at

the closing date. The basis difference at December 31, 2008, was approximately $4.6 billion. Equity earnings in 2008 and 2007 were increased by $246 million and $202 million, respectively, due to amortization of this basis difference. We are the operator and managing partner of WRB. EnCana is obligated to contribute $7.5 billion, plus accrued interest, to WRB over a 10-year period beginning in 2007. For the Wood River refinery, operating results are shared 50/50 starting upon formation. For the Borger refinery, we were entitled to 85 percent of the operating results in 2007, with our share decreasing to 65 percent in 2008, and 50 percent in all years thereafter.

LUKOIL

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

Because LUKOIL's accounting cycle close and preparation of U.S. GAAP financial statements occur subsequent to our reporting deadline, our equity earnings and statistics for our LUKOIL investment are estimated, based on current market indicators, publicly available LUKOIL information, and other objective data. Once the difference between actual and estimated results is known, an adjustment is recorded. This estimate-to-actual adjustment will be a recurring component of future period results. Any difference between our estimate of fourth-quarter 2008 and the actual LUKOIL U.S. GAAP net income will be reported in our 2009 equity earnings.

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

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

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

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

NMNG

NMNG is a joint venture with LUKOIL, created in June 2005, to develop resources in the northern part of Russia's Timan-Pechora province. We have a 30 percent direct ownership interest with a 50 percent governance interest. NMNG is working to develop the Yuzhno Khylchuyu (YK) field, which achieved initial production in June 2008. Production from the NMNG joint venture fields is transported via pipeline to LUKOIL's existing terminal at Varandey Bay on the Barents Sea and then shipped via tanker to international markets. We use the equity method of accounting for this joint venture.

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

DCP Midstream

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

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

DCP Midstream markets a portion of its natural gas liquids to us and CPChem under a supply agreement that continues until December 31, 2014. This purchase commitment is on an "if-produced, will-purchase" basis and so has no fixed production schedule, but has had, and is expected over the remaining term of

the contract to have, a relatively stable purchase pattern. Natural gas liquids are purchased under this agreement at various published market index prices, less transportation and fractionation fees.

CPChem

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

Loans to Related Parties

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

Significant loans to affiliated companies include the following:

- We entered into a credit agreement with Freeport LNG, whereby we provided loan financing of approximately $650 million, excluding accrued interest, for the construction of an LNG facility which became operational in June 2008. The loan was converted from a construction loan to a term loan in August 2008, and Freeport started making repayments in September 2008. At the time of the loan conversion in August, it consisted of $650 million of principal and $124 million of accrued interest. As of December 31, 2008, the outstanding loan balance was $757 million.
- We had an obligation to provide loan financing to Varandey Terminal Company for 30 percent of the costs of the terminal expansion. Terminal construction was completed in June 2008, and the final loan amount was $275 million at December 2008 exchange rates, excluding accrued interest. Although repayments were not required to start until May 2010, Varandey used available cash to repay $12 million of interest in the second half of 2008. The outstanding accrued interest at December 31, 2008, was $38 million at December exchange rates.
- Qatargas 3 is an integrated project to produce and liquefy natural gas from Qatar's North field. We own a 30 percent interest in the project. The other participants in the project are affiliates of Qatar Petroleum (68.5 percent) and Mitsui & Co., Ltd. (1.5 percent). Our interest is held through a jointly owned company, Qatar Liquefied Gas Company Limited (3), for which we use the equity method of accounting. Qatargas 3 secured project financing of $4 billion in December 2005, consisting of $1.3 billion of loans from export credit agencies (ECA), $1.5 billion from commercial banks, and $1.2 billion from ConocoPhillips. The ConocoPhillips loan facilities have substantially the same terms as the ECA and commercial bank facilities. Prior to project completion certification, all loans, including the ConocoPhillips loan facilities, are guaranteed by the participants based on their respective ownership interests. Accordingly, our maximum exposure to this financing structure is $1.2 billion. Upon completion certification, which is expected in 2011, all project loan facilities, including the ConocoPhillips loan facilities, will become nonrecourse to the project participants. At December 31, 2008, Qatargas 3 had $3.0 billion outstanding under all the loan facilities, of which ConocoPhillips provided $835 million, and an additional $76 million of accrued interest.

Note 8 — Properties, Plants and Equipment

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

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

Suspended Wells

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

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

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

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

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

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

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

[1]*Additional appraisal wells planned.*
[2]*Appraisal drilling complete; costs being incurred to assess development.*

Note 9 — Goodwill and Intangibles

Changes in the carrying amount of goodwill are as follows:

	Millions of Dollars		
	E&P	R&M	Total
Balance at December 31, 2006	$27,712	3,776	31,488
Goodwill allocated to expropriated assets	(1,925)	—	(1,925)
Acquired (Burlington Resources adjustment)	172	—	172
Goodwill allocated to assets held for sale or sold	(191)	(3)	(194)
Tax and other adjustments	(199)	(6)	(205)
Balance at December 31, 2007	25,569	3,767	29,336
Goodwill impairment	**(25,443)**	**—**	**(25,443)**
Goodwill allocated to assets held for sale or sold	**(148)**	**—**	**(148)**
Tax and other adjustments	**22**	**11**	**33**
Balance at December 31, 2008	**$ —**	**3,778**	**3,778**

Goodwill Impairment

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

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

Because quoted market prices for our reporting units are not available, management must apply judgment in determining the estimated fair value of these reporting units for purposes of performing the annual goodwill impairment test. Management uses all available information to make these fair value determinations, including the present values of expected future cash flows using discount rates commensurate with the risks involved in the assets. A key component of these fair value determinations is a reconciliation of the sum of these net present value calculations to our market capitalization. We use an average of our market capitalization over the 30 calendar days preceding the impairment testing date as being more reflective of our stock price trend than a single day, point-in-time market price. Because, in our judgment, Worldwide E&P is considered to have a higher valuation volatility than Worldwide R&M, the long-term free cash flow growth rate implied from this reconciliation to our recent average market capitalization is applied to the Worldwide E&P net present value calculation.

The accounting principles regarding goodwill acknowledge that the observed market prices of individual trades of a company's stock (and thus its computed market capitalization) may not be representative of the fair value of the company as a whole. Substantial value may arise from the ability to take advantage of synergies and other benefits that flow from control over another entity. Consequently, measuring the fair value of a collection of assets and liabilities that operate together in a controlled entity is different from measuring the fair value of that entity's individual common stock. In most industries, including ours, an acquiring entity typically is willing to pay more for equity securities that give

it a controlling interest than an investor would pay for a number of equity securities representing less than a controlling interest. Therefore, once the above net present value calculations have been determined, we also add a control premium to the calculations. This control premium is judgmental and is based on observed acquisitions in our industry. The resultant fair values calculated for the reporting units are then compared to observable metrics on large mergers and acquisitions in our industry to determine whether those valuations, in our judgment, appear reasonable.

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

- Adjusting the carrying value of major equity method investments to their estimated fair values.
- Adjusting the carrying value of properties, plants and equipment (PP&E) to the estimated aggregate fair value of all oil and gas property interests.
- Recalculating deferred income taxes under FASB Statement No. 109, "Accounting for Income Taxes," after considering the likely tax basis a hypothetical buyer would have in the assets and liabilities.

When determining the above adjustment for the estimated aggregate fair value of PP&E, it was noted that in order for any residual purchase price to be allocated to goodwill, the purchase price assigned to PP&E would have to be well below the value of the PP&E implied by recently-observed metrics from other sales of major oil and gas properties.

Based on the above analysis, we concluded that a $25.4 billion before- and after-tax noncash impairment of the entire amount of recorded goodwill for the Worldwide E&P reporting unit was required. This impairment was recorded in the fourth quarter of 2008.

Venezuela Expropriation

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

Intangible Assets

Information on the carrying value of intangible assets follows:

	Millions of Dollars		
	Gross Carrying Amount	Accumulated Amortization	Net Carrying Amount
Amortized Intangible Assets			
Balance at December 31, 2008			
Technology related	**$120**	**(60)**	**60**
Refinery air permits	**14**	**(10)**	**4**
Contract based	**116**	**(81)**	**35**
Other	**36**	**(27)**	**9**
	$286	**(178)**	**108**
Balance at December 31, 2007			
Technology related	$145	(60)	85
Refinery air permits	14	(8)	6
Contract based	124	(62)	62
Other	37	(25)	12
	$320	(155)	165
Indefinite-Lived Intangible Assets			
Balance at December 31, 2008			
Trade names and trademarks	**$494**		
Refinery air and operating permits	**244**		
	$738		
Balance at December 31, 2007			
Trade names and trademarks	$494		
Refinery air and operating permits	237		
	$731		

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

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

Note 10 — Impairments

Goodwill

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

LUKOIL

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

Expropriated Assets

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

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

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

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

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

Other Impairments

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

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

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

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

Also during 2008, we recorded property impairments of:

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

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

- Increased asset retirement obligations for properties at the end of their economic life for certain fields, primarily located in the North Sea, totaling $175 million.
- Downward reserve revisions and higher projected operating costs for fields in the United States, Canada and the United Kingdom, totaling $80 million.
- An abandoned project in Alaska resulting from increased taxes, totaling $28 million.

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

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

During 2006, we recorded impairments of $496 million associated with planned asset dispositions in our E&P and R&M segments, comprised of properties, plants and equipment ($196 million), trademark intangibles ($70 million), and goodwill ($230 million). In the fourth quarter of 2006, we

recorded an impairment of $131 million associated with assets in the Canadian Rockies Foothills area, as a result of declining well performance and drilling results. We recorded a property impairment of $40 million in 2006 as a result of our decision to withdraw an application for a license under the federal Deepwater Port Act, associated with a proposed LNG regasification terminal located offshore Alabama.

Note 11 — Asset Retirement Obligations and Accrued Environmental Costs

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

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

**Classified as a current liability on the balance sheet, under the caption "Other accruals." Includes $14 million and $23 million related to assets held for sale in 2008 and 2007, respectively. See Note 6 — Assets Held for Sale, for additional information.*

Asset Retirement Obligations

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

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

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

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

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

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

Accrued Environmental Costs

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

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

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

Note 12 — Debt

Long-term debt at December 31 was:

	Millions of Dollars	
	2008	2007
9.875% Debentures due 2010	**$ 150**	150
9.375% Notes due 2011	**328**	328
9.125% Debentures due 2021	**150**	150
8.75% Notes due 2010	**1,264**	1,264
8.20% Debentures due 2025	**150**	150
8.125% Notes due 2030	**600**	600
7.9% Debentures due 2047	**100**	100
7.8% Debentures due 2027	**300**	300
7.68% Notes due 2012	**30**	37
7.65% Debentures due 2023	**88**	88
7.625% Debentures due 2013	**100**	100
7.40% Notes due 2031	**500**	500
7.375% Debentures due 2029	**92**	92
7.25% Notes due 2031	**500**	500
7.20% Notes due 2031	**575**	575
7.125% Debentures due 2028	**—**	300
7% Debentures due 2029	**200**	200
6.95% Notes due 2029	**1,549**	1,549
6.875% Debentures due 2026	**67**	67
6.68% Notes due 2011	**400**	400
6.65% Debentures due 2018	**297**	297
6.50% Notes due 2011	**500**	500
6.40% Notes due 2011	**178**	178
6.375% Notes due 2009	**284**	284
6.35% Notes due 2011	**1,750**	1,750
5.951% Notes due 2037	**645**	645
5.95% Notes due 2036	**500**	500
5.90% Notes due 2032	**505**	505
5.90% Notes due 2038	**600**	—
5.625% Notes due 2016	**1,250**	1,250
5.50% Notes due 2013	**750**	750
5.30% Notes due 2012	**350**	350
5.20% Notes due 2018	**500**	—
4.75% Notes due 2012	**897**	897
4.40% Notes due 2013	**400**	—
Commercial paper at 1.05% – 1.76% at year-end 2008 and 4.05% – 5.36% at year-end 2007	**6,933**	725
Floating Rate Five-Year Term Note due 2011 at 1.638% at year-end 2008 and 5.0625% at year-end 2007	**1,500**	3,000
Floating Rate Notes due 2009 at 4.42% at year-end 2008 and 5.34% at year-end 2007	**950**	950
Industrial Development Bonds due 2012 through 2038 at 0.93% – 5.75% at year-end 2008 and 3.50% – 5.75% at year-end 2007	**252**	252
Guarantee of savings plan bank loan payable due 2015 at 2.46% at year-end 2008 and 5.40% at year-end 2007	**140**	175
Note payable to Merey Sweeny, L.P. due 2020 at 7%*	**163**	172
Marine Terminal Revenue Refunding Bonds due 2031 at 0.40% – 1.00% at year-end 2008 and 3.40% – 3.51% at year-end 2007	**265**	265
Other	**36**	50
Debt at face value	**26,788**	20,945
Capitalized leases	**28**	54
Net unamortized premiums and discounts	**639**	688
Total debt	**27,455**	21,687
Short-term debt	**(370)**	(1,398)
Long-term debt	**$27,085**	20,289

**Related party.*

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

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

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

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

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

Our revolving credit facilities may be used as direct bank borrowings, as support for issuances of letters of credit totaling up to $750 million, as support for our commercial paper programs, or as support of up to $250 million on commercial paper issued by TransCanada Keystone Pipeline LP, a Keystone pipeline joint venture entity. The revolving credit facilities are broadly syndicated among financial institutions and do not contain any material adverse change provisions or any covenants requiring maintenance of specified financial ratios or ratings. The facility agreements contain a cross-default provision relating to the failure to pay principal or interest on other debt obligations of $200 million or more by ConocoPhillips, or by any of its consolidated subsidiaries.

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

we had access to $2.6 billion in borrowing capacity under our revolving credit facilities at December 31, 2008.

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

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

Note 13 — Joint Venture Acquisition Obligation

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

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

Note 14 — Guarantees

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

Construction Completion Guarantees

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

Guarantees of Joint Venture Debt

- In June 2006, we issued a guarantee for 24 percent of the $2 billion in credit facilities of Rockies Express Pipeline LLC, which will be used to construct a natural gas pipeline across a portion of the United States. At December 31, 2008, Rockies Express had $1,561 million outstanding under the credit facilities, with our 24 percent guarantee equaling $375 million. The maximum potential amount of future payments to third-party lenders under the guarantee is estimated to be $480 million, which could become payable if the credit facilities are fully utilized and Rockies Express fails to meet its obligations under the credit agreement. In addition, we also have a guarantee for 24 percent of $600 million of Floating Rate Notes due 2009 issued by Rockies Express. It is anticipated final construction completion will be achieved in 2009, and refinancing will take place at that time, making the debt nonrecourse to ConocoPhillips. At December 31, 2008, the total carrying value of these guarantees to third-party lenders was $12 million.
- In December 2007, we acquired a 50 percent equity interest in four Keystone pipeline entities (Keystone), to create a joint venture with TransCanada Corporation. Keystone is constructing a crude oil pipeline originating in Alberta, with delivery points in Illinois and Oklahoma. In December 2008, we provided a guarantee for up to $250 million of balances outstanding under a commercial paper program. This program was established by Keystone to provide funding for a portion of Keystone's construction costs attributable to our ownership interest in the project. Payment under the guarantee would be due in the event Keystone failed to repay principal and interest, when due, to short-term noteholders. The commercial paper program and our guarantee are expected to increase as funding needs increase during construction of the Keystone pipeline. Keystone's other owner will guarantee a similar, but separate, funding vehicle. Post-construction Keystone financing is anticipated to be nonrecourse to us. At December 31, 2008, $200 million was outstanding under the Keystone commercial paper program guaranteed by us.
- At December 31, 2008, we had other guarantees outstanding for our portion of joint venture debt obligations, which have terms of up to 17 years. The maximum potential amount of future payments under the guarantees is approximately $90 million. Payment would be required if a joint venture defaults on its debt obligations.

Other Guarantees

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

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

  In addition to the above guarantee, in order to obtain long-term shipping commitments that would enable a pipeline expansion starting at Hardisty, Alberta, and extending to near Port Arthur, Texas, the Keystone owners executed an agreement in July 2008 to guarantee Keystone's obligations under its agreement to provide transportation at a specified price for certain shippers to the Gulf Coast. Although our guarantee is for 50 percent of these obligations, TransCanada has agreed to reimburse us for amounts we pay in excess of our ownership percentage in Keystone. Our maximum potential amount of future payments, or cost of volume delivery, under this guarantee, after such reimbursement, is estimated to be $220 million ($550 million before reimbursement) based on a full 20-year term of the shipping commitments, which could become payable if Keystone fails to meet its obligations under the agreements and the obligations cannot otherwise be mitigated. Future payments are considered unlikely, as the payments, or cost of volume delivery, are contingent upon Keystone defaulting on its obligation to construct the pipeline in accordance with the terms of the agreement.
- We have other guarantees with maximum future potential payment amounts totaling $520 million, which consist primarily of dealer and jobber loan guarantees to support our marketing business, guarantees to fund the short-term cash liquidity deficits of certain joint ventures, a guarantee of minimum charter revenue for two LNG vessels, one small construction completion guarantee, guarantees relating to the startup of a refining joint venture, guarantees of the lease payment obligations of a joint venture, and guarantees of the residual value of leased corporate aircraft. These guarantees generally extend up to 16 years or life of the venture.

Indemnifications

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

Note 15 — Contingencies and Commitments

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

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

Environmental

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

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

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

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

See Note 11 — Asset Retirement Obligations and Accrued Environmental Costs, for a summary of our accrued environmental liabilities.

Legal Proceedings

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

Other Contingencies

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

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

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

Note 16 — Financial Instruments and Derivative Contracts

Derivative Instruments

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

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

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

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

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

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

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

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

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

- Balance physical systems. In addition to cash settlement prior to contract expiration, exchange traded futures contracts may also be settled by physical delivery of the commodity, providing another source of supply to meet our refinery requirements or marketing demand.
- Meet customer needs. Consistent with our policy to generally remain exposed to market prices, we use swap contracts to convert fixed-price sales contracts, which are often requested by natural gas and refined product consumers, to a floating market price.
- Manage the risk to our cash flows from price exposures on specific crude oil, natural gas, refined product and electric power transactions.

- Enable us to use the market knowledge gained from these activities to do a limited amount of trading not directly related to our physical business. For the years ended December 31, 2008, 2007 and 2006, the gains or losses from this activity were not material to our cash flows or net income.

Credit Risk

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

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

Fair Values of Financial Instruments

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

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

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

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

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

Note 17 — Preferred Stock and Minority Interests

Preferred Stock

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

Minority Interests

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

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

Note 18 — Preferred Share Purchase Rights

In 2002, our Board of Directors authorized and declared a dividend of one preferred share purchase right for each common share outstanding, and authorized and directed the issuance of one right per common share for any newly issued shares. The rights have certain anti-takeover effects. The rights will cause substantial dilution to a person or group that attempts to acquire ConocoPhillips on terms not approved by the Board of Directors. However, since the rights may either be redeemed or otherwise made inapplicable by ConocoPhillips prior to an acquiror obtaining beneficial ownership of 15 percent or more of ConocoPhillips' common stock, the rights should not interfere with any merger or business combination approved by the Board of Directors prior to that occurrence. The rights, which expire June 30, 2012, will be exercisable only if a person or group acquires 15 percent or more of the company's common stock or commences a tender offer that would result in ownership of 15 percent or more of the common stock. Each right would entitle stockholders to buy one one-hundredth of a share of preferred stock at an exercise price of $300. If an acquiror obtains 15 percent or more of ConocoPhillips' common stock, then each right will be adjusted so that it will entitle the holder (other than the acquiror, whose rights will become void) to purchase, for the then exercise price, a number of shares of ConocoPhillips' common stock equal in value to two times the exercise price of the right. In addition, the rights enable holders to purchase the stock of an acquiring company at a discount, depending on specific circumstances. We may redeem the rights in whole, but not in part, for one cent per right.

Note 19 — Non-Mineral Leases

The company leases ocean transport vessels, tugboats, barges, pipelines, railcars, corporate aircraft, service stations, drilling equipment, computers, office buildings and other facilities and equipment. Certain leases include escalation clauses for adjusting rental payments to reflect changes in price indices, as well as renewal options and/or options to purchase the leased property for the fair market value at the end of the lease term. There are no significant restrictions imposed on us by the leasing agreements in regards to dividends, asset dispositions or borrowing ability. Leased assets under capital leases were not significant in any period presented.

At December 31, 2008, future minimum rental payments due under noncancelable leases were:

	Millions of Dollars
2009	$ 868
2010	731
2011	526
2012	453
2013	274
Remaining years	917
Total	3,769
Less income from subleases	(174)*
Net minimum operating lease payments	$3,595

**Includes $76 million related to railcars subleased to Chevron Phillips Chemical Company LLC, a related party.*

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

	Millions of Dollars		
	2008	2007	2006
Total rentals*	**$1,033**	855	698
Less sublease rentals	**(125)**	(82)	(103)
	$ 908	773	595

**Includes $22 million, $27 million and $29 million of contingent rentals in 2008, 2007 and 2006, respectively. Contingent rentals primarily are related to retail sites and refining equipment, and are based on volume of product sold or throughput.*

Note 20 — Employee Benefit Plans

Pension and Postretirement Plans

An analysis of the projected benefit obligations for our pension plans and accumulated benefit obligations for our postretirement health and life insurance plans follows:

	Millions of Dollars					
	Pension Benefits				Other Benefits	
	2008		2007		**2008**	2007
	U.S.	**Int'l.**	U.S.	Int'l.		
Change in Benefit Obligation						
Benefit obligation at January 1	**$ 4,281**	**3,085**	4,113	3,087	**792**	778
Service cost	**186**	**100**	175	98	**11**	14
Interest cost	**247**	**198**	229	161	**47**	45
Plan participant contributions	**—**	**10**	—	10	**32**	28
Medicare Part D subsidy	**—**	**—**	—	—	**8**	6
Plan amendments	**8**	**—**	2	(68)	**(47)**	—
Actuarial (gain) loss	**230**	**(180)**	109	(294)	**18**	(6)
Acquisitions	**—**	**—**	—	—	**—**	—
Divestitures	**—**	**—**	—	—	**—**	—
Benefits paid	**(332)**	**(117)**	(347)	(97)	**(85)**	(81)
Curtailment	**—**	**—**	—	1	**—**	—
Recognition of termination benefits	**—**	**2**	—	1	**—**	—
Foreign currency exchange rate change	**—**	**(791)**	—	186	**(8)**	8
Benefit obligation at December 31*	**$ 4,620**	**2,307**	4,281	3,085	**768**	792
**Accumulated benefit obligation portion of above at December 31:*	***$ 4,022***	***1,946***	*3,666*	*2,550*		
Change in Fair Value of Plan Assets						
Fair value of plan assets at January 1	**$ 3,138**	**2,601**	2,863	2,185	**3**	3
Acquisitions	**—**	**—**	—	—	**—**	—
Divestitures	**—**	**—**	—	—	**—**	—
Actual return on plan assets	**(840)**	**(342)**	237	169	**(1)**	—
Company contributions	**407**	**170**	385	185	**45**	47
Plan participant contributions	**—**	**10**	—	10	**32**	28
Medicare Part D subsidy	**—**	**—**	—	—	**8**	6
Benefits paid	**(332)**	**(117)**	(347)	(97)	**(85)**	(81)
Foreign currency exchange rate change	**—**	**(594)**	—	149	**—**	—
Fair value of plan assets at December 31:	**$ 2,373**	**1,728**	3,138	2,601	**2**	3
Funded Status	**$(2,247)**	**(579)**	(1,143)	(484)	**(766)**	(789)
Amounts Recognized in the Consolidated Balance Sheet at December 31						
Noncurrent assets	**$ —**	**33**	—	98	**—**	—
Current liabilities	**(6)**	**(9)**	(6)	(9)	**(49)**	(50)
Noncurrent liabilities	**(2,241)**	**(603)**	(1,137)	(573)	**(717)**	(739)
Total recognized	**$(2,247)**	**(579)**	(1,143)	(484)	**(766)**	(789)

	Millions of Dollars					
	Pension Benefits				Other Benefits	
	2008		2007		**2008**	2007
	U.S.	**Int'l.**	U.S.	Int'l.		
Weighted-Average Assumptions Used to Determine Benefit Obligations at December 31						
Discount rate	**6.25%**	**6.00**	6.00	5.90	**6.30**	6.20
Rate of compensation increase	**4.00**	**4.20**	4.00	4.80	**—**	—
Weighted-Average Assumptions Used to Determine Net Periodic Benefit Cost for Years Ended December 31						
Discount rate	**6.00%**	**5.90**	5.75	5.15	**6.20**	5.95
Expected return on plan assets	**7.00**	**6.80**	7.00	6.50	**7.00**	7.00
Rate of compensation increase	**4.00**	**4.80**	4.00	4.70	**—**	—

For both U.S. and international pensions, the overall expected long-term rate of return is developed from the expected future return of each asset class, weighted by the expected allocation of pension assets to that asset class. We rely on a variety of independent market forecasts in developing the expected rate of return for each class of assets.

At December 31, 2007, all of our plans used a December 31 measurement date, except for a plan in the United Kingdom, which had a September 30 measurement date. To comply with the provisions of SFAS No. 158, "Employers' Accounting for Defined Benefit Pension and Other Postretirement Plans — an amendment of FASB Statements No. 87, 88, 106, and 132(R)," we changed the measurement date for the U.K. plan from September 30 to December 31 for our 2008 consolidated financial statements. We elected to implement the change by remeasuring the U.K. plan assets and obligations as of December 31, 2007. To implement the change in measurement date, we recognized the $10 million (net of tax) of net periodic pension cost incurred from October 1, 2007, to December 31, 2007, as an adjustment to 2008 beginning retained earnings.

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

	Millions of Dollars					
	Pension Benefits				Other Benefits	
	2008		2007		**2008**	2007
	U.S.	**Int'l.**	U.S.	Int'l.		
Unrecognized net actuarial loss (gain)	**$ 1,798**	**335**	587	123	**(149)**	(185)
Unrecognized prior service cost	**69**	**(22)**	71	(30)	**(43)**	15

	Millions of Dollars					
	Pension Benefits				Other Benefits	
	2008		2007		**2008**	2007
	U.S.	**Int'l.**	U.S.	Int'l.		
Sources of Change in Other Comprehensive Income						
Net gain (loss) arising during the period	**$(1,275)**	**(229)**	(72)	289	**(19)**	5
Amortization of gain (loss) included in income	**64**	**17**	62	48	**(17)**	(20)
Net gain (loss) during the period	**$(1,211)**	**(212)**	(10)	337	**(36)**	(15)
Prior service cost arising during the period	**$ (8)**	**(9)**	(2)	67	**47**	—
Amortization of prior service cost included in income	**10**	**1**	10	7	**11**	13
Net prior service cost during the period	**$ 2**	**(8)**	8	74	**58**	13

Amounts included in accumulated other comprehensive income at December 31, 2008, that are expected to be amortized into net periodic postretirement cost during 2009 are provided below:

	Millions of Dollars		
	Pension Benefits		Other Benefits
	U.S.	Int'l.	
Unrecognized net actuarial loss (gain)	$186	33	(15)
Unrecognized prior service cost	11	1	9

For our tax-qualified pension plans with projected benefit obligations in excess of plan assets, the projected benefit obligation, the accumulated benefit obligation, and the fair value of plan assets were $6,092 million, $5,289 million, and $3,624 million at December 31, 2008, respectively, and $6,392 million, $5,417 million, and $5,056 million at December 31, 2007, respectively.

For our unfunded nonqualified key employee supplemental pension plans, the projected benefit obligation and the accumulated benefit obligation were $391 million and $334 million, respectively, at December 31, 2008, and were $390 million and $344 million, respectively, at December 31, 2007.

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

	Millions of Dollars								
	Pension Benefits						Other Benefits		
	2008		2007		2006		**2008**	2007	2006
	U.S.	**Int'l.**	U.S.	Int'l.	U.S.	Int'l.			
Components of Net Periodic Benefit Cost									
Service cost	**$ 186**	**85**	175	98	174	87	**11**	14	14
Interest cost	**247**	**170**	229	161	210	134	**47**	45	47
Expected return on plan assets	**(223)**	**(170)**	(204)	(147)	(169)	(121)	**—**	—	—
Amortization of prior service cost	**10**	**1**	10	7	9	7	**11**	13	19
Recognized net actuarial loss (gain)	**64**	**17**	62	48	89	41	**(17)**	(20)	(16)
Net periodic benefit cost	**$ 284**	**103**	272	167	313	148	**52**	52	64

We recognized pension settlement losses of $18 million, $2 million and $11 million and special termination benefits of $2 million, $1 million and $1 million in 2008, 2007 and 2006, respectively. Curtailment losses of $1 million were recognized in 2007.

In determining net pension and other postretirement benefit costs, we amortize prior service costs on a straight-line basis over the average remaining service period of employees expected to receive benefits under the plan. For net gains and losses, we amortize 10 percent of the unamortized balance each year.

We have multiple nonpension postretirement benefit plans for health and life insurance. The health care plans are contributory and subject to various cost sharing features, with participant and company contributions adjusted annually; the life insurance plans are noncontributory. The measurement of the accumulated postretirement benefit obligation assumes a health care cost trend rate of 8.5 percent in 2009 that declines to 5.0 percent by 2023. A one-percentage-point change in the assumed health care cost trend rate would have the following effects on the 2008 amounts:

	Millions of Dollars	
	One-Percentage-Point	
	Increase	Decrease
Effect on total of service and interest cost components	$1	(1)
Effect on the postretirement benefit obligation	6	(5)

Plan Assets — We follow a policy of broadly diversifying pension plan assets across asset classes, investment managers, and individual holdings. Asset classes that are considered appropriate include U.S. equities, non-U.S. equities, U.S. fixed income, non-U.S. fixed income, real estate, and private equity investments. Plan fiduciaries may consider and add other asset classes to the investment program from time to time. Our funding policy for U.S. plans is to contribute at least the minimum required by the Employee Retirement Income Security Act of 1974 and the Internal Revenue Code of 1986, as amended. Contributions to foreign plans are dependent upon local laws and tax regulations. In 2009, we expect to contribute approximately $930 million to our domestic qualified and nonqualified pension and postretirement benefit plans and $150 million to our international qualified and nonqualified pension and postretirement benefit plans.

A portion of U.S. pension plan assets is held as a participating interest in an insurance annuity contract. This participating interest is calculated as the market value of investments held under this contract, less the accumulated benefit obligation covered by the contract. At December 31, 2008, the participating interest in the annuity contract was valued at $138 million and consisted of $400 million in debt securities, less $262 million for the accumulated benefit obligation covered by the contract. At December 31, 2007, the participating interest in the annuity contract was valued at $159 million and consisted of $201 million in debt securities and $229 million in equity securities, less $271 million for the accumulated benefit obligation covered by the contract. The participating interest is not available for meeting general pension benefit obligations in the near term. No future company contributions are required and no new benefits are being accrued under this insurance annuity contract.

In the United States, plan asset allocation is managed on a gross asset basis, which includes the market value of all investments held under the insurance annuity contract. On this basis, the weighted-average asset allocations are as follows:

	Pension					
	U.S.			International		
	2008	2007	Target	**2008**	2007	Target
Asset Category						
Equity securities	**52%**	64	60	**39**	48	51
Debt securities	**48**	36	30	**56**	46	42
Real estate	**—**	—	5	**4**	5	6
Other	**—**	—	5	**1**	1	1
	100%	100	100	**100**	100	100

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

Treating the participating interest in the annuity contract as a separate asset category results in the following weighted-average asset allocations:

	Pension			
	U.S.		International	
	2008	2007	**2008**	2007
Asset Category				
Equity securities	**58%**	62	**39**	48
Debt securities	**36**	33	**56**	46
Participating interest in annuity contract	**6**	5	**—**	—
Real estate	**—**	—	**4**	5
Other	**—**	—	**1**	1
	100%	100	**100**	100

The following benefit payments, which are exclusive of amounts to be paid from the participating annuity contract and which reflect expected future service, as appropriate, are expected to be paid:

	Millions of Dollars			
	Pension Benefits		Other Benefits	
	U.S.	Int'l.	Gross	Subsidy Receipts
2009	$ 373	79	50	2
2010	380	83	53	—
2011	469	86	56	—
2012	442	91	58	—
2013	470	97	60	—
2014–2018	2,771	578	329	—

Severance Accrual

As a result of the current business environment's impact on our operating and capital plans, a reduction in our overall employee work force is expected in 2009. Various business units and staff groups recorded accruals in the fourth quarter of 2008 for severance and related employee benefits totaling $162 million, all of which is classified as short-term.

Defined Contribution Plans

Most U.S. employees (excluding retail service station employees) are eligible to participate in either the ConocoPhillips Savings Plan (CPSP) or the Burlington Resources Savings Plan (BR Savings Plan). Employees can deposit up to 30 percent of their eligible pay up to the statutory limit ($15,500 in 2008) in the thrift feature of the CPSP to a choice of approximately 43 investment funds. ConocoPhillips matches contribution deposits, up to 1.25 percent of eligible pay. Company contributions charged to expense for the CPSP and predecessor plans, excluding the stock savings feature (discussed below), were $22 million in 2008, $21 million in 2007, and $19 million in 2006. For the BR Savings Plan, ConocoPhillips matches deposits, up to 6 percent or 8 percent of the employee's eligible pay based upon years of service. During 2008, ConocoPhillips contributed $5 million to the BR Savings Plan, to match eligible contributions by employees.

Assets of the BR Savings Plan were merged into the CPSP effective at close of business on December 31, 2008, and the BR Savings Plan participants became participants in CPSP.

The stock savings feature of the CPSP is a leveraged employee stock ownership plan. Employees may elect to participate in the stock savings feature by contributing 1 percent of eligible pay and receiving an allocation of shares of common stock proportionate to the amount of contribution.

In 1990, the Long-Term Stock Savings Plan of Phillips Petroleum Company (now the stock savings feature of the CPSP) borrowed funds that were used to purchase previously unissued shares of company common stock. Since the company guarantees the CPSP's borrowings, the unpaid balance is reported as a liability of the company and unearned compensation is shown as a reduction of common stockholders' equity. Dividends on all shares are charged against retained earnings. The debt is serviced by the CPSP from company contributions and dividends received on certain shares of common stock held by the plan, including all unallocated shares. The shares held by the stock savings feature of the CPSP are released for allocation to participant accounts based on debt service payments on CPSP borrowings. In addition, during the period from 2009 through 2012, when no debt principal payments are scheduled to occur, we have committed to make direct contributions of stock to the stock savings feature of the CPSP, or make prepayments on CPSP borrowings, to ensure a certain minimum level of stock allocation to participant accounts.

We recognize interest expense as incurred and compensation expense based on the fair market value of the stock contributed or on the cost of the unallocated shares released, using the shares-allocated method. We recognized total CPSP expense related to the stock savings feature of $111 million, $148 million and $126 million in 2008, 2007 and 2006, respectively, all of which was compensation expense. In 2008, 2007 and 2006, we contributed 1,668,456 shares, 1,856,224 shares and 1,921,688 shares, respectively, of company common stock from the Compensation and Benefits Trust. The shares had a fair market value of $120 million, $155 million and $132 million, respectively. Dividends used to service debt were $41 million, $39 million and $37 million in 2008, 2007 and 2006, respectively. These dividends reduced the amount of compensation expense recognized each period. Interest incurred on the CPSP debt in 2008, 2007 and 2006 was $6 million, $11 million and $12 million, respectively.

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

	2008	2007
Unallocated shares	**7,208,150**	9,040,949
Allocated shares	**18,000,395**	17,648,368
Total shares	**25,208,545**	26,689,317

The fair value of unallocated shares at December 31, 2008 and 2007, was $373 million and $798 million, respectively.

We have several defined contribution plans for our international employees, each with its own terms and eligibility depending on location. Total compensation expense recognized for these international plans was approximately $53 million in 2008, $44 million in 2007 and $39 million in 2006.

Share-Based Compensation Plans

The 2004 Omnibus Stock and Performance Incentive Plan (the Plan) was approved by shareholders in May 2004. Over its 10-year life, the Plan allows the issuance of up to 70 million shares of our common stock for compensation to our employees, directors and consultants. After approval of the Plan, the heritage plans were no longer used for further awards. Of the 70 million shares available for issuance under the Plan, 40 million shares of common stock are available for incentive stock options, and no more than 40 million shares may be used for awards in stock.

Our share-based compensation programs generally provide accelerated vesting (i.e., a waiver of the remaining period of service required to earn an award) for awards held by employees at the time of their retirement. For share-based awards granted prior to our adoption of SFAS No. 123(R), we recognize expense over the period of time during which the employee earns the award, accelerating the recognition of expense only when an employee actually retires. For share-based awards granted after our adoption of SFAS No. 123(R) on January 1, 2006, we recognize share-based compensation expense over the shorter of: 1) the service period (i.e., the stated period of time required to earn the award); or 2) the period beginning at the start of the service period and ending when an employee first becomes eligible for retirement, but not less than six months, as this is the minimum period of time required for an award to not be subject to forfeiture.

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

Total share-based compensation expense recognized in income and the associated tax benefit for the three years ended December 31, 2008, was as follows:

	Millions of Dollars		
	2008	2007	2006
Compensation cost	**$193**	242	140
Tax benefit	**67**	85	54

Stock Options — Stock options granted under the provisions of the Plan and earlier plans permit purchase of our common stock at exercise prices equivalent to the average market price of the stock on the date the options were granted. The options have terms of 10 years and generally vest ratably, with one-third of the options awarded vesting and becoming exercisable on each anniversary date following the date of grant. Options awarded to employees already eligible for retirement vest within six months of the grant date, but those options do not become exercisable until the end of the normal vesting period.

The following summarizes our stock option activity for the three years ended December 31, 2008:

	Options	Weighted-Average Exercise Price	Weighted-Average Grant-Date Fair Value	Millions of Dollars Aggregate Intrinsic Value
Outstanding at December 31, 2005	57,396,746	$27.31		
Burlington Resources acquisition at March 31, 2006	4,927,116	33.95		
Granted	1,809,281	59.33	$16.16	
Exercised	(9,737,765)	24.32		$416
Forfeited	(341,759)	60.58		
Expired	(4,840)	50.16		
Outstanding at December 31, 2006	54,048,779	$29.31		
Granted	2,530,648	66.37	$17.86	
Exercised	(12,176,988)	26.29		$926
Forfeited	(268,177)	65.02		
Expired or cancelled	(29,407)	17.00		
Outstanding at December 31, 2007	44,104,855	$32.06		
Granted	**2,211,202**	**79.35**	**$18.66**	
Exercised	**(9,493,818)**	**28.39**		**$535**
Forfeited	**(184,148)**	**73.91**		
Expired or cancelled	**(22,338)**	**42.65**		
Outstanding at December 31, 2008	**36,615,753**	**$35.65**		
Vested at December 31, 2008	**34,062,503**	**$32.94**		**$693**
Exercisable at December 31, 2008	**32,607,060**	**$31.16**		**$693**

The weighted-average remaining contractual term of vested options and exercisable options at December 31, 2008, was 3.98 years and 3.77 years, respectively.

During 2008, we received $260 million in cash and realized a tax benefit of $161 million from the exercise of options. At December 31, 2008, the remaining unrecognized compensation expense from unvested options was $18 million, which will be recognized over a weighted-average period of 11 months, the longest period being 25 months.

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

	2008	2007	2006
Assumptions used			
Risk-free interest rate	**3.21%**	4.77	4.63
Dividend yield	**2.50%**	2.50	2.50
Volatility factor	**27.78%**	26.10	26.10
Expected life (years)	**5.82**	6.70	7.18

The ranges in the assumptions used were as follows:

	2008		2007		2006	
	High	**Low**	High	Low	High	Low
Ranges used						
Risk-free interest rate	**3.45%**	**2.27**	4.90	4.77	5.15	4.54
Dividend yield	**2.50**	**2.50**	2.50	2.50	2.50	2.50
Volatility factor	**32.10**	**26.70**	26.10	26.10	26.50	25.90

We calculate volatility using all of the ConocoPhillips end-of-week closing stock prices available since the merger of Conoco and Phillips Petroleum on August 31, 2002, and will continue to do so until the span of data used equals the expected life of the options granted. We periodically calculate the average period of time lapsed between grant dates and exercise dates of past grants to estimate the expected life of new option grants.

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

The following summarizes our stock unit activity for the three years ended December 31, 2008:

	Stock Units	Weighted-Average Grant-Date Fair Value	Millions of Dollars Total Fair Value
Outstanding at December 31, 2005	3,892,404	$38.34	
Granted	1,480,294	57.77	
Forfeited	(118,461)	45.92	
Issued	(167,099)		$11
Outstanding at December 31, 2006	5,087,138	$43.75	
Granted	1,721,521	65.33	
Forfeited	(162,992)	52.57	
Issued	(975,756)		$36
Outstanding at December 31, 2007	5,669,911	$51.30	
Granted	**1,797,803**	**77.42**	
Forfeited	**(128,888)**	**62.82**	
Issued	**(1,411,128)**		**$59**
Outstanding at December 31, 2008	**5,927,698**	**$61.16**	
Not vested at December 31, 2008	**5,285,087**	**$60.50**	

At December 31, 2008, the remaining unrecognized compensation cost from the unvested units was $161 million, which will be recognized over a weighted-average period of 25 months, the longest period being 49 months.

Performance Share Program — Under the Plan, we also annually grant to senior management restricted stock units that do not vest until either (i) with respect to awards for periods beginning before 2009, the employee becomes eligible for retirement by reaching age 55 with five years of service or (ii) with respect to awards for periods beginning in 2009, five years after the grant date of the award (although recipients can elect to defer the lapsing of restrictions until retirement after reaching age 55 with five years of service), so we recognize compensation expense for these awards beginning on the date of grant and ending on the date the units are scheduled to vest. Since these awards are authorized three years prior to the grant date, for employees eligible for such retirement by or shortly after the grant date, we recognize compensation expense over the period beginning on the date of authorization and ending on the date of grant. These units are settled by issuing one share of ConocoPhillips common stock per unit, generally when the employee retires from ConocoPhillips. Until issued as stock, recipients of the units receive a quarterly cash payment of a dividend equivalent that is charged to expense. In its current form, the first grant of units under this program was in 2006.

The following summarizes our Performance Share Program activity for the three years ended December 31, 2008:

	Performance Share Stock Units	Weighted-Average Grant-Date Fair Value	Millions of Dollars Total Fair Value
Outstanding at December 31, 2005	—	$ —	
Granted	1,641,216	59.08	
Issued	(184,975)		$12
Outstanding at December 31, 2006	1,456,241	$59.08	
Granted	1,349,475	66.37	
Forfeited	(22,062)	62.45	
Issued	(178,357)		$12
Outstanding at December 31, 2007	2,605,297	$62.49	
Granted	**1,291,453**	**79.38**	
Forfeited	**(30,862)**	**69.24**	
Issued	**(689,710)**		**$58**
Outstanding at December 31, 2008	**3,176,178**	**$68.13**	
Not Vested at December 31, 2008	**1,319,719**	**$43.41**	

At December 31, 2008, the remaining unrecognized compensation cost from unvested Performance Share awards was $57 million, which will be recognized over a weighted-average period of 47 months, the longest period being 12 years.

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

The following summarizes the aggregate activity of these restricted shares and units for the three years ended December 31, 2008:

	Stock Units	Weighted-Average Grant-Date Fair Value	Millions of Dollars Total Fair Value
Outstanding at December 31, 2005	3,344,941	$29.16	
Granted	248,421	64.48	
Burlington Resources acquisition	523,769	64.95	
Issued	(239,257)		$16
Cancelled	(275,499)	47.56	
Outstanding at December 31, 2006	3,602,375	$33.68	
Granted	293,024	67.30	
Issued	(227,766)		$17
Cancelled	(180,489)	50.39	
Outstanding at December 31, 2007	3,487,144	$34.41	
Granted	**237,642**	**78.59**	
Issued	**(128,803)**		**$ 9**
Cancelled	**(231,963)**	**40.08**	
Outstanding at December 31, 2008	**3,364,020**	**$36.75**	
Not vested at December 31, 2008	**313,974**	**$72.95**	

At December 31, 2008, the remaining unrecognized compensation cost from the unvested units was $12 million, which will be recognized over a weighted-average period of 18 months, the longest period being 25 months.

Compensation and Benefits Trust

The Compensation and Benefits Trust (CBT) is an irrevocable grantor trust, administered by an independent trustee and designed to acquire, hold and distribute shares of our common stock to fund certain future compensation and benefit obligations of the company. The CBT does not increase or alter the amount of benefits or compensation that will be paid under existing plans, but offers us enhanced financial flexibility in providing the funding requirements of those plans. We also have flexibility in determining the timing of distributions of shares from the CBT to fund compensation and benefits, subject to a minimum distribution schedule. The trustee votes shares held by the CBT in accordance with voting directions from eligible employees, as specified in a trust agreement with the trustee.

We sold 58.4 million shares of previously unissued company common stock to the CBT in 1995 for $37 million of cash, previously contributed to the CBT by us, and a promissory note from the CBT to us of $952 million. The CBT is consolidated by ConocoPhillips; therefore, the cash contribution and promissory note are eliminated in consolidation. Shares held by the CBT are valued at cost and do not affect earnings per share or total common stockholders' equity until after they are transferred out of the CBT. In 2008 and 2007, shares transferred out of the CBT were 1,668,456 and 1,856,224, respectively. At December 31, 2008, the CBT had 40.5 million shares remaining. All shares are required to be transferred out of the CBT by January 1, 2021. The CBT, together with two smaller grantor trusts, comprise the "Grantor trusts" line in the equity section of the consolidated balance sheet.

Note 21 — Income Taxes

Income taxes charged to income (loss) were:

	Millions of Dollars		
	2008	2007	2006
Income Taxes			
Federal			
Current	**$ 3,245**	3,944	4,313
Deferred	**(227)**	312	(77)
Foreign			
Current	**10,268**	7,035	7,581
Deferred	**(312)**	(474)	392
State and local			
Current	**543**	602	622
Deferred	**(112)**	(38)	(48)
	$13,405	11,381	12,783

Deferred income taxes reflect the net tax effect of temporary differences between the carrying amounts of assets and liabilities for financial reporting purposes and the amounts used for tax purposes. Major components of deferred tax liabilities and assets at December 31 were:

	Millions of Dollars	
	2008	2007
Deferred Tax Liabilities		
Properties, plants and equipment, and intangibles	**$20,563**	23,344
Investment in joint ventures	**1,778**	1,300
Inventory	**283**	197
Partnership income deferral	**1,172**	1,501
Other	**564**	725
Total deferred tax liabilities	**24,360**	27,067
Deferred Tax Assets		
Benefit plan accruals	**1,819**	1,603
Asset retirement obligations and accrued environmental costs	**3,232**	3,135
Deferred state income tax	**289**	390
Other financial accruals and deferrals	**712**	539
Loss and credit carryforwards	**1,657**	1,716
Other	**338**	251
Total deferred tax assets	**8,047**	7,634
Less valuation allowance	**(1,340)**	(1,269)
Net deferred tax assets	**6,707**	6,365
Net deferred tax liabilities	**$17,653**	20,702

Current assets, long-term assets, current liabilities and long-term liabilities included deferred taxes of $457 million, $58 million, $1 million and $18,167 million, respectively, at December 31, 2008, and $329 million, $26 million, $39 million and $21,018 million, respectively, at December 31, 2007.

We have loss and credit carryovers in multiple taxing jurisdictions. These attributes generally expire between 2009 and 2028 with some carryovers having indefinite carryforward periods.

Valuation allowances have been established for certain loss and credit carryforwards that reduce deferred tax assets to an amount that will, more likely than not, be realized. During 2008, valuation allowances increased a total of $71 million. This reflects increases of $303 million primarily related to U.S. foreign tax credit and foreign and state tax loss carryforwards, partially offset by decreases of $232 million related to utilization of credits and loss carryforwards, currency effects and asset relinquishment. Based on our historical taxable income, expectations for the future, and available tax-planning strategies, management expects remaining net deferred tax assets will be realized as offsets to reversing deferred tax liabilities and as offsets to the tax consequences of future taxable income. None of

the future tax benefit for recognition of deferred tax assets that have valuation allowances, if any, will be allocated to goodwill due to the effect of SFAS No. 141 (Revised), "Business Combinations" (SFAS No. 141(R)). For additional information on SFAS No. 141(R), see Note 27 — New Accounting Standards.

At December 31, 2008 and 2007, income considered to be permanently reinvested in certain foreign subsidiaries and foreign corporate joint ventures totaled approximately $3,319 million and $6,606 million, respectively. The change from 2007 relates primarily to the impairment of our LUKOIL investment in 2008. Deferred income taxes have not been provided on this income, as we do not plan to initiate any action that would require the payment of income taxes. It is not practicable to estimate the amount of additional tax that might be payable on this foreign income if distributed.

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

The following table shows a reconciliation of the beginning and ending unrecognized tax benefits for 2007 and 2008.

	Millions of Dollars	
	2008	2007
Balance at January 1	**$1,143**	912
Additions based on tax positions related to the current year	**7**	273
Additions for tax positions of prior years	**186**	145
Reductions for tax positions of prior years	**(249)**	(168)
Settlements	**(16)**	(15)
Lapse of statute	**(3)**	(4)
Balance at December 31	**$1,068**	1,143

Included in the balance of unrecognized tax benefits for 2008 and 2007 were $862 million and $698 million, respectively, which, if recognized, would affect our effective tax rate. The increase from 2007 was primarily due to the effect of SFAS No. 141(R).

At December 31, 2008 and 2007, accrued liabilities for interest and penalties totaled $147 million and $137 million, respectively, net of accrued income taxes. Interest and penalties affecting earnings in 2008 and 2007 were $28 million and $46 million, respectively.

We and our subsidiaries file tax returns in the U.S. federal jurisdiction and in many foreign and state jurisdictions. Audits in major jurisdictions are generally complete as follows: United Kingdom (2001), Canada (2003), United States (2004) and Norway (2007). Issues in dispute for audited years and audits for subsequent years are ongoing and in various stages of completion in the many jurisdictions in which we operate around the world. As a consequence, the balance in unrecognized tax benefits can be expected to fluctuate from period to period. It is reasonably possible such changes could be significant when compared with our total unrecognized tax benefits, but the amount of change is not estimable.

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

	Millions of Dollars			Percent of Pretax Income		
	2008	2007	2006	**2008**	2007	2006
Income (loss) before income taxes						
United States	**$ 10,050**	13,939	13,376	**(279.7)%**	59.9	47.2
Foreign	**11,800**	9,333	14,957	**(328.4)**	40.1	52.8
Goodwill impairment	**(25,443)**	—	—	**708.1**	—	—
	$ (3,593)	23,272	28,333	**100.0%**	100.0	100.0
Federal statutory income tax	**$ (1,257)**	8,145	9,917	**35.0%**	35.0	35.0
Goodwill impairment	**8,905**	—	—	**(247.8)**	—	—
Foreign taxes in excess of federal statutory rate	**5,694**	3,254	2,697	**(158.5)**	14.0	9.5
Federal manufacturing deduction	**(182)**	(250)	(119)	**5.1**	(1.1)	(0.4)
State income tax	**280**	367	373	**(7.8)**	1.6	1.3
Other	**(35)**	(135)	(85)	**0.9**	(0.6)	(0.3)
	$ 13,405	11,381	12,783	**(373.1)%**	48.9	45.1

Our effective tax rate in 2008 was a negative 373 percent, compared with a positive 49 percent in 2007. The change in the effective tax rate for 2008 was primarily due to the impact of impairments relating to goodwill and to our LUKOIL investment taken in the fourth quarter of 2008. For additional information on the impairments, see Note 9 — Goodwill and Intangibles and Note 7 — Investments, Loans and Long-Term Receivables.

Tax rate changes in 2008 did not have a significant impact on our 2008 income tax expense. Our 2007 tax expense was decreased $204 million and $141 million, respectively, due to remeasurement of deferred tax liabilities resulting from tax rate reductions in Canada and Germany. Our 2006 tax expense was increased $470 million due to remeasurement of deferred tax liabilities and the current year impact of increases in the U.K. tax rate. This was mostly offset by a 2006 reduction in tax expense of $435 million due to the remeasurement of deferred tax liabilities from the 2006 Canadian graduated tax rate reduction and an Alberta provincial tax rate change.

Note 22 — Other Comprehensive Income (Loss)

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

	Millions of Dollars		
	Before-Tax	Tax Expense (Benefit)	After-Tax
2008			
Defined benefit pension plans:			
Prior service cost arising during the year	**$ 30**	**22**	**8**
Reclassification adjustment for amortization of prior service cost included in net loss	**22**	**8**	**14**
Net prior service cost	**52**	**30**	**22**
Net loss arising during the year	**(1,523)**	**(535)**	**(988)**
Reclassification adjustment for amortization of prior net losses included in net loss	**64**	**26**	**38**
Net loss	**(1,459)**	**(509)**	**(950)**
Nonsponsored plans*	**(41)**	**—**	**(41)**
Foreign currency translation adjustments	**(5,552)**	**(88)**	**(5,464)**
Hedging activities	**(4)**	**(2)**	**(2)**
Other comprehensive loss	**$ (7,004)**	**(569)**	**(6,435)**
2007			
Defined benefit pension plans:			
Prior service cost arising during the year	$ 65	20	45
Reclassification adjustment for amortization of prior service cost included in net income	30	12	18
Net prior service cost	95	32	63
Net gain arising during the year	222	67	155
Reclassification adjustment for amortization of prior net losses included in net income	90	32	58
Net gain	312	99	213
Nonsponsored plans*	(2)	—	(2)
Foreign currency translation adjustments	3,214	139	3,075
Hedging activities	(3)	1	(4)
Other comprehensive income	$ 3,616	271	3,345
2006			
Minimum pension liability adjustment	$ 53	20	33
Foreign currency translation adjustments	913	(100)	1,013
Hedging activities	4	—	4
Other comprehensive income	$ 970	(80)	1,050

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

Deferred taxes have not been provided on temporary differences related to foreign currency translation adjustments for investments in certain foreign subsidiaries and foreign corporate joint ventures that are considered permanent in duration.

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

	Millions of Dollars	
	2008	2007
Defined benefit pension liability adjustments	**$ (1,434)**	(465)
Foreign currency translation adjustments	**(431)**	5,033
Deferred net hedging loss	**(10)**	(8)
Accumulated other comprehensive income (loss)	**$ (1,875)**	4,560

Note 23 — Cash Flow Information

	Millions of Dollars		
	2008	2007	2006
Noncash Investing and Financing Activities			
Issuance of stock and options for the acquisition of Burlington Resources	**$ —**	—	16,343
Investment in an upstream business venture through issuance of an acquisition obligation	**—**	7,313	—
Investment in a downstream business venture through contribution of noncash assets and liabilities	**—**	2,428	—
Increase in PP&E related to an increase in asset retirement obligations	**1,117**	919	464
Cash Payments			
Interest	**$ 858**	1,040	958
Income taxes	**13,122**	11,330	13,050

Note 24 — Other Financial Information

	Millions of Dollars Except Per Share Amounts		
	2008	2007	2006
Interest and Debt Expense			
Incurred			
Debt	**$ 1,189**	1,369	1,409
Other	**314**	449	136
	1,503	1,818	1,545
Capitalized	**(568)**	(565)	(458)
Expensed	**$ 935**	1,253	1,087
Other Income			
Interest income	**$ 245**	342	165
Gain on asset dispositions	**891**	1,348	116
Business interruption insurance recoveries*	**2**	52	239
Other, net	**(48)**	229	165
	$ 1,090	1,971	685

**Primarily related to 2005 hurricanes in the Gulf of Mexico and southern United States.*

Research and Development Expenditures — expensed	**$ 209**	160	117
Advertising Expenses	**$ 96**	84	87
Shipping and Handling Costs*	**$ 1,443**	1,493	1,415

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

Cash Dividends paid per common share	**$ 1.88**	1.64	1.44
Foreign Currency Transaction Gains (Losses) — after-tax			
E&P	**$ 216**	216	(44)
Midstream	**1**	(2)	—
R&M	**(173)**	(13)	60
LUKOIL Investment	**(27)**	5	—
Chemicals	**—**	—	—
Emerging Businesses	**(7)**	1	1
Corporate and Other	**(72)**	(120)	65
	$ (62)	87	82

Note 25 — Related Party Transactions

Significant transactions with related parties were:

	Millions of Dollars		
	2008	2007	2006*
Operating revenues (a)	**$13,097**	10,949	8,808
Purchases (b)**	**19,409**	15,722	7,072
Operating expenses and selling, general and administrative expenses (c)	**515**	416	386
Net interest expense (d)	**66**	99	(13)

**Restated to include additional related party transactions.*
***The increase in 2007 is primarily due to purchases from the WRB business venture.*

(a) We sold natural gas to DCP Midstream and crude oil to the Malaysian Refining Company Sdn. Bhd. (MRC), among others, for processing and marketing. Natural gas liquids, solvents and petrochemical feedstocks were sold to Chevron Phillips Chemical Company LLC (CPChem), gas oil and hydrogen feedstocks were sold to Excel Paralubes and refined products were sold primarily to CFJ Properties and LUKOIL. Natural gas, crude oil, blendstock and other intermediate products were sold to WRB Refining LLC. In addition, we charged several of our affiliates, including CPChem, Merey Sweeny L.P. (MSLP) and Hamaca Holding LLC (until expropriation on June 26, 2007), for the use of common facilities, such as steam generators, waste and water treaters, and warehouse facilities.

(b) We purchased refined products from WRB. We purchased natural gas and natural gas liquids from DCP Midstream and CPChem for use in our refinery processes and other feedstocks from various affiliates. We purchased crude oil from LUKOIL, upgraded crude oil from Petrozuata C.A. (until expropriation on June 26, 2007) and refined products from MRC. We also paid fees to various pipeline equity companies for transporting finished refined products, as well as a price upgrade to MSLP for heavy crude processing. We purchased base oils and fuel products from Excel Paralubes for use in our refinery and specialty businesses.

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

(d) We paid and/or received interest to/from various affiliates, including FCCL Oil Sands Partnership. See Note 7 — Investments, Loans and Long-Term Receivables, for additional information on loans to affiliated companies.

Note 26 — Segment Disclosures and Related Information

We have organized our reporting structure based on the grouping of similar products and services, resulting in six operating segments:

1) E&P — This segment primarily explores for, produces, transports and markets crude oil, natural gas and natural gas liquids on a worldwide basis. At December 31, 2008, our E&P operations were producing in the United States, Norway, the United Kingdom, Canada, Ecuador, Australia, offshore Timor-Leste in the Timor Sea, Indonesia, China, Vietnam, Libya, Nigeria, Algeria and Russia. The E&P segment's U.S. and international operations are disclosed separately for reporting purposes.
2) Midstream — This segment gathers, processes and markets natural gas produced by ConocoPhillips and others, and fractionates and markets natural gas liquids, predominantly in the United States and Trinidad. The Midstream segment primarily consists of our 50 percent equity investment in DCP Midstream, LLC.
3) R&M — This segment purchases, refines, markets and transports crude oil and petroleum products, mainly in the United States, Europe and Asia. At December 31, 2008, we owned or had an interest in 12 refineries in the United States, one in the United Kingdom, one in Ireland, two in Germany, and one in Malaysia. The R&M segment's U.S. and international operations are disclosed separately for reporting purposes.
4) LUKOIL Investment — This segment represents our investment in the ordinary shares of OAO LUKOIL, an international, integrated oil and gas company headquartered in Russia. At December 31, 2008, our ownership interest was 20 percent based on issued shares and 20.06 percent based on estimated shares outstanding. See Note 7 — Investments, Loans and Long-Term Receivables, for additional information.
5) Chemicals — This segment manufactures and markets petrochemicals and plastics on a worldwide basis. The Chemicals segment consists of our 50 percent equity investment in Chevron Phillips Chemical Company LLC.
6) Emerging Businesses — This segment represents our investment in new technologies or businesses outside our normal scope of operations. Activities within this segment are currently focused on power generation and innovation of new technologies, such as those related to conventional and nonconventional hydrocarbon recovery (including heavy oil), refining, alternative energy, biofuels and the environment.

Corporate and Other includes general corporate overhead, most interest expense, discontinued operations, restructuring charges, and various other corporate activities. Corporate assets include all cash and cash equivalents.

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

Analysis of Results by Operating Segment

	Millions of Dollars		
	2008	2007	2006
Sales and Other Operating Revenues			
E&P			
United States	**$ 51,378**	36,974	35,335
International	**36,972**	24,617	28,111
Intersegment eliminations — U.S.	**(8,034)**	(6,096)	(5,438)
Intersegment eliminations — international	**(10,498)**	(7,341)	(7,842)
E&P	**69,818**	48,154	50,166
Midstream			
Total sales	**6,791**	5,106	4,461
Intersegment eliminations	**(227)**	(245)	(1,037)
Midstream	**6,564**	4,861	3,424
R&M			
United States	**117,727**	96,154	95,314
International	**47,520**	38,598	35,439
Intersegment eliminations — U.S.	**(965)**	(540)	(855)
Intersegment eliminations — international	**(52)**	(11)	(21)
R&M	**164,230**	134,201	129,877
LUKOIL Investment	**—**	—	—
Chemicals	**11**	10	13
Emerging Businesses			
Total sales	**1,060**	656	675
Intersegment eliminations	**(861)**	(458)	(515)
Emerging Businesses	**199**	198	160
Corporate and Other	**20**	13	10
Consolidated sales and other operating revenues	**$240,842**	187,437	183,650
Depreciation, Depletion, Amortization and Impairments			
E&P			
United States	**$ 3,725**	3,328	2,901
International	**5,096**	9,121	3,445
Goodwill impairment	**25,443**	—	—
Total E&P	**34,264**	12,449	6,346
Midstream	**6**	14	29
R&M			
United States	**1,129**	609	1,014
International	**425**	139	458
Total R&M	**1,554**	748	1,472
LUKOIL Investment	**7,410**	—	—
Chemicals	**—**	—	—
Emerging Businesses	**193**	39	58
Corporate and Other	**124**	78	62
Consolidated depreciation, depletion, amortization and impairments	**$ 43,551**	13,328	7,967

	Millions of Dollars		
	2008	2007	2006
Equity in Earnings of Affiliates			
E&P			
United States	**$ 57**	11	20
International	**235**	302	782
Total E&P	**292**	313	802
Midstream	**810**	599	618
R&M			
United States	**836**	1,710	466
International	**178**	240	151
Total R&M	**1,014**	1,950	617
LUKOIL Investment	**2,011***	1,875	1,481
Chemicals	**128**	350	665
Emerging Businesses	**(5)**	—	5
Corporate and Other	**—**	—	—
Consolidated equity in earnings of affiliates	**$ 4,250**	5,087	4,188

**Does not include a $7,410 million impairment for our LUKOIL investment presented as a separate line item in the consolidated statement of operations.*

Income Taxes			
E&P			
United States	**$ 2,617**	2,231	2,545
International	**9,621**	6,372	7,584
Total E&P	**12,238**	8,603	10,129
Midstream	**261**	237	248
R&M			
United States	**934**	2,571	2,334
International	**214**	113	218
Total R&M	**1,148**	2,684	2,552
LUKOIL Investment	**49**	45	37
Chemicals	**15**	(13)	171
Emerging Businesses	**(6)**	(33)	(2)
Corporate and Other	**(300)**	(142)	(352)
Consolidated income taxes	**$ 13,405**	11,381	12,783
Net Income (Loss)			
E&P			
United States	**$ 4,988**	4,248	4,348
International	**6,976**	367	5,500
Goodwill impairment	**(25,443)**	—	—
Total E&P	**(13,479)**	4,615	9,848
Midstream	**541**	453	476
R&M			
United States	**1,540**	4,615	3,915
International	**782**	1,308	566
Total R&M	**2,322**	5,923	4,481
LUKOIL Investment	**(5,488)**	1,818	1,425
Chemicals	**110**	359	492
Emerging Businesses	**30**	(8)	15
Corporate and Other	**(1,034)**	(1,269)	(1,187)
Consolidated net income (loss)	**$ (16,998)**	11,891	15,550

	Millions of Dollars		
	2008	2007	2006
Investments In and Advances To Affiliates			
E&P			
United States	**$ 1,368**	1,059	690
International	**16,772**	12,055	4,346
Total E&P	**18,140**	13,114	5,036
Midstream	**1,033**	1,178	1,319
R&M			
United States	**3,677**	3,500	698
International	**1,326**	1,091	948
Total R&M	**5,003**	4,591	1,646
LUKOIL Investment	**5,452**	11,162	9,564
Chemicals	**2,186**	2,203	2,255
Emerging Businesses	**75**	79	—
Corporate and Other	**—**	—	—
Consolidated investments in and advances to affiliates*	**$ 31,889**	32,327	19,820
**Includes amounts classified as held for sale:*	***$ 2***	*48*	*158*

	Millions of Dollars		
	2008	2007	2006
Capital Expenditures and Investments*			
E&P			
United States	**$ 5,250**	3,788	2,828
International	**11,206**	6,147	6,685
Total E&P	**16,456**	9,935	9,513
Midstream	**4**	5	4
R&M			
United States	**1,643**	1,146	1,597
International	**626**	240	1,419
Total R&M	**2,269**	1,386	3,016
LUKOIL Investment	**—**	—	2,715
Chemicals	**—**	—	—
Emerging Businesses	**156**	257	83
Corporate and Other	**214**	208	265
Consolidated capital expenditures and investments	**$19,099**	11,791	15,596

**Net of cash acquired.*

	Millions of Dollars		
	2008	2007	2006
Total Assets			
E&P			
United States	**$ 36,962**	35,160	35,523
International	**58,912**	59,412	48,143
Goodwill	**—**	25,569	27,712
Total E&P	**95,874**	120,141	111,378
Midstream	**1,455**	2,016	2,045
R&M			
United States	**22,554**	24,336	22,936
International	**7,942**	9,766	9,135
Goodwill	**3,778**	3,767	3,776
Total R&M	**34,274**	37,869	35,847
LUKOIL Investment	**5,455**	11,164	9,564
Chemicals	**2,217**	2,225	2,379
Emerging Businesses	**924**	1,230	977
Corporate and Other	**2,666**	3,112	2,591
Consolidated total assets	**$142,865**	177,757	164,781

	Millions of Dollars		
	2008	2007	2006
Interest Income and Expense			
Interest income			
Corporate	**$ 128**	246	106
E&P	**115**	96	57
R&M	**2**	—	—
Interest and debt expense			
Corporate	**762**	1,066	1,087
E&P	**173**	187	—

Geographic Information

	Millions of Dollars					
	Sales and Other Operating Revenues*			Long-Lived Assets**		
	2008	2007	2006	**2008**	2007	2006
United States	**$166,496**	131,433	127,869	**52,972**	50,714	48,418
Australia***	**2,735**	1,633	1,836	**8,656**	3,420	3,542
Canada	**5,226**	4,727	5,554	**20,429**	24,758	14,831
Norway	**3,036**	2,479	2,480	**5,002**	6,180	4,982
Russia	**—**	—	—	**7,604**	13,359	10,886
United Kingdom	**29,699**	20,680	19,510	**5,844**	7,995	7,755
Other foreign countries	**33,650**	26,485	26,401	**15,919**	14,904	15,607
Worldwide consolidated	**$240,842**	187,437	183,650	**116,426**	121,330	106,021

**Sales and other operating revenues are attributable to countries based on the location of the operations generating the revenues.*
***Defined as net properties, plants and equipment plus investments in and advances to affiliated companies. Includes amounts classified as held for sale.*
****Includes amounts related to the joint petroleum development area with shared ownership held by Australia and Timor-Leste.*

Note 27 — New Accounting Standards

In December 2007, the FASB issued SFAS No. 141 (Revised), "Business Combinations" (SFAS No. 141(R)). This Statement will apply to all transactions in which an entity obtains control of one or more other businesses. In general, SFAS No. 141(R) requires the acquiring entity in a business combination to recognize the fair value of all the assets acquired and liabilities assumed in the transaction; establishes the acquisition date as the fair value measurement point; and modifies the disclosure requirements. Additionally, it changes the accounting treatment for transaction costs, acquired contingent arrangements, in-process research and development, restructuring costs, changes in deferred tax asset valuation allowances as a result of business combination, and changes in income tax uncertainties after the acquisition date. This Statement applies prospectively to business combinations for which the acquisition date is on or after January 1, 2009. However, starting January 1, 2009, accounting for changes in valuation allowances for acquired deferred tax assets and the resolution of uncertain tax positions for prior business combinations will impact tax expense instead of impacting goodwill.

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

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

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

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

Oil and Gas Operations (Unaudited)

In accordance with SFAS No. 69, "Disclosures about Oil and Gas Producing Activities," and regulations of the U.S. Securities and Exchange Commission (SEC), we are making certain supplemental disclosures about our oil and gas exploration and production operations. While this information was developed with reasonable care and disclosed in good faith, we emphasize some of the data is necessarily imprecise and represents only approximate amounts because of the subjective judgments involved in developing such information. Accordingly, this information may not necessarily represent our current financial condition or our expected future results.

These disclosures include information about our consolidated oil and gas activities and our proportionate share of our equity affiliates' oil and gas activities, covering both those in our Exploration and Production (E&P) segment, as well as in our LUKOIL Investment segment. As a result, amounts reported as Equity Affiliates in Oil and Gas Operations may differ from those shown in the individual segment disclosures reported elsewhere in this report. The data included for the LUKOIL Investment segment reflects the company's estimated share of OAO LUKOIL's amounts. Because LUKOIL's accounting cycle close and preparation of U.S. GAAP financial statements occur subsequent to our reporting deadline, our equity share of financial information and statistics for our LUKOIL investment are estimated based on current market indicators, publicly available LUKOIL information, and other objective data. Once the difference between actual and estimated results is known, an adjustment is recorded. Our estimated year-end 2008 reserves related to our equity investment in LUKOIL are based on LUKOIL's year-end 2008 reserve estimates and include adjustments to conform them to ConocoPhillips' reserves policy.

Our proved reserves include estimated quantities related to production sharing contracts (PSCs), which are reported under the "economic interest" method and are subject to fluctuations in prices of crude oil, natural gas and natural gas liquids; recoverable operating expenses; and capital costs. If costs remain stable, reserve quantities attributable to recovery of costs will change inversely to changes in commodity prices. For example, if prices increase, then our applicable reserve quantities would decline. At December 31, 2008, approximately 14 percent of our total proved reserves, excluding LUKOIL, were under PSCs, primarily in our Asia Pacific geographic reporting area.

Our disclosures by geographic area for our consolidated operations include the United States, Canada, Europe (primarily Norway and the United Kingdom), Asia Pacific, Middle East and Africa, Russia and Caspian, and Other Areas (primarily South America). In these supplemental oil and gas disclosures, where we use equity accounting for operations that have proved reserves, these operations are shown separately and designated as Equity Affiliates, and include Canada, Asia Pacific, Middle East and Africa, Russia and Caspian, and Other Areas. Canada includes our share of the FCCL Oil Sands Partnership. Asia Pacific includes our share of Australia Pacific LNG's coalbed methane exploration and production activities. Middle East and Africa includes Qatargas 3. The Russia and Caspian area includes our share of Polar Lights Company, OOO Naryanmarneftegaz, and LUKOIL. Other Areas consists of the Petrozuata and Hamaca heavy-oil projects in Venezuela, which were expropriated on June 26, 2007.

On December 31, 2008, the SEC issued its final rules to modernize the supplemental oil and gas disclosures. Significant changes have occurred in our industry in the nearly three decades since the SEC first adopted its oil and gas disclosure rules, which include guidance on determining the volumetric measure of proved reserves. The new rules require the use of 12-month historical average prices using first-of-the-month pricing. The final rules also allow for companies to include nontraditional resources, such as bitumen extracted from oil sands, in their SEC-reported reserves. We expect to include Syncrude in our SEC proved reserves reporting as allowed under the new rules. We are currently evaluating the final rules and have not yet determined the overall impact to our proved reserve determinations. Our year-end 2009 reserve determinations and the oil and gas disclosures in our 2009 Form 10-K are expected to be subject to the new rules, based on current effective dates.

Reserves Governance

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

We have a companywide, comprehensive, SEC-compliant internal policy that governs the determination and reporting of proved reserves. This policy is applied by the geologists and reservoir engineers in our E&P business units around the world. As part of our internal control process, each business unit's reserves are reviewed annually by an internal team composed of reservoir engineers, geologists and finance personnel for adherence to SEC guidelines and company policy through on-site visits and review of documentation. In addition to providing independent reviews of the business units' recommended reserve changes, this internal team also ensures reserves are calculated using consistent and appropriate standards and procedures. This team is independent of business unit line management and is responsible for reporting its findings to senior management and our internal audit group. The team is responsible for maintaining and communicating our reserves policy and procedures and is available for internal peer reviews and consultation on major projects or technical issues throughout the year. All of our proved crude oil, natural gas and natural gas liquids reserves held by consolidated companies and our share of equity affiliates have been estimated by ConocoPhillips, with assistance from third-party petroleum engineering consultants with regard to our equity interests in LUKOIL and Australia Pacific LNG.

During 2008, approximately 34 percent of our year-end 2007 E&P proved reserves were reviewed by an outside third-party petroleum engineering consulting firm. At the present time, we plan to continue to have an outside firm review a similar percentage of our reserve base during 2009.

Engineering estimates of the quantities of recoverable oil and gas reserves in oil and gas fields and in-place crude bitumen volumes in oil sand mining operations are inherently imprecise. See the "Critical Accounting Estimates" section of Management's Discussion and Analysis of Financial Condition and Results of Operations for additional discussion of the sensitivities surrounding these estimates.

Proved Reserves Worldwide

Years Ended December 31	Crude Oil										
	Millions of Barrels										
	Consolidated Operations										
	Alaska	Lower 48	Total U.S.	Canada	Europe	Asia Pacific	Middle East and Africa	Russia and Caspian	Other Areas	Total	Equity Affiliates
Developed and Undeveloped											
End of 2005	1,505	170	1,675	44	808	274	328	190	17	3,336	2,430
Revisions	(118)	(11)	(129)	58	(65)	(12)	(18)	(74)	2	(238)	(35)
Improved recovery	13	1	14	—	5	63	—	—	—	82	—
Purchases	—	181	181	16	—	13	42	—	17	269	393
Extensions and discoveries	53	9	62	4	6	8	3	—	—	83	74
Production	(97)	(37)	(134)	(9)	(90)	(39)	(39)	—	(3)	(314)	(171)
Sales	—	(18)	(18)	—	—	—	—	—	—	(18)	(1)
End of 2006	1,356	295	1,651	113	664	307	316	116	33	3,200	2,690
Revisions	24	19	43	28	10	(23)	(13)	1	(3)	43	202
Improved recovery	25	16	41	—	—	—	—	—	—	41	—
Purchases	—	—	—	—	—	—	—	—	—	—	403
Extensions and discoveries	26	15	41	3	8	73	16	—	—	141	303
Production	(96)	(36)	(132)	(7)	(76)	(32)	(29)	—	(4)	(280)	(172)
Sales	—	(1)	(1)	(16)	(1)	(6)	—	—	(17)	(41)	(1,028)
End of 2007	1,335	308	1,643	121	605	319	290	117	9	3,104	2,398
Revisions	(189)	(40)	(229)	19	(17)	16	14	9	—	(188)	34
Improved recovery	23	5	28	—	—	—	—	—	—	28	—
Purchases	—	—	—	—	—	—	—	—	—	—	2
Extensions and discoveries	13	21	34	2	9	13	5	—	—	63	88
Production	(90)	(33)	(123)	(9)	(77)	(33)	(28)	—	(3)	(273)	(164)
Sales	—	—	—	—	—	—	—	(11)	—	(11)	(41)
End of 2008	1,092	261	1,353	133	520	315	281	115	6	2,723	2,317
Equity affiliates											
End of 2005	—	—	—	—	—	—	46	1,295	1,089	—	2,430
End of 2006	—	—	—	—	—	—	60	1,607	1,023	—	2,690
End of 2007	—	—	—	623	—	—	70	1,705	—	—	2,398
End of 2008	—	—	—	700	—	—	70	1,547	—	—	2,317
Developed											
Consolidated operations											
End of 2005	1,359	158	1,517	42	409	202	326	—	—	2,496	—
End of 2006	1,254	281	1,535	50	359	181	292	—	13	2,430	—
End of 2007	1,238	281	1,519	51	337	146	259	—	9	2,321	—
End of 2008	994	227	1,221	56	316	170	263	—	6	2,032	—
Equity affiliates											
End of 2005	—	—	—	—	—	—	—	1,013	472	—	1,485
End of 2006	—	—	—	—	—	—	—	1,293	369	—	1,662
End of 2007	—	—	—	45	—	—	—	1,336	—	—	1,381
End of 2008	—	—	—	105	—	—	—	1,211	—	—	1,316

Notable changes in proved crude oil reserves in the three years ending December 31, 2008, included:

- *Revisions:* In 2008, revisions in Alaska were mainly due to lower prices at December 31, 2008, compared with December 31, 2007. In 2007 for our equity affiliate operations, revisions were primarily attributable to LUKOIL. In 2006, revisions in Alaska were primarily a result of reservoir performance.
- *Purchases:* In 2007 for our equity affiliate operations, purchases reflect the formation of FCCL. In 2006, purchases in the Lower 48 were primarily related to our acquisition of Burlington Resources. In 2006 for our equity affiliate operations, purchases were mainly attributable to acquiring additional interests in LUKOIL.
- *Extensions and Discoveries:* In 2007 for our equity affiliate operations, extensions and discoveries were primarily associated with FCCL.
- *Sales:* In 2007 for our equity affiliates, sales were primarily due to the expropriation of our oil interests in Venezuela.

In addition to conventional crude oil, natural gas and natural gas liquids (NGL) proved reserves, we have proved oil sands mining reserves in Canada, associated with a Syncrude project totaling 249 million barrels at the end of 2008. For internal management purposes, we view these mining reserves and their development as part of our total exploration and production operations. However, SEC regulations currently in effect define these reserves as mining related. Therefore, they are not included in our tabular presentation of proved crude oil, natural gas and NGL reserves. These oil sands mining reserves also are not included in the standardized measure of discounted future net cash flows relating to proved oil and gas reserve quantities.

Years Ended December 31	Natural Gas										
	Billions of Cubic Feet										
	Consolidated Operations										
	Alaska	Lower 48	Total U.S.	Canada	Europe	Asia Pacific	Middle East and Africa	Russia and Caspian	Other Areas	Total	Equity Affiliates
Developed and Undeveloped											
End of 2005	3,472	4,114	7,586	970	3,062	3,700	1,061	129	5	16,513	2,548
Revisions	43	(87)	(44)	(123)	(293)	71	(64)	(31)	(39)	(523)	(310)
Improved recovery	—	4	4	—	1	—	—	—	—	5	—
Purchases	6	5,258	5,264	2,466	432	25	94	—	129	8,410	325
Extensions and discoveries	23	551	574	353	64	6	58	—	—	1,055	925
Production	(130)	(770)	(900)	(356)	(414)	(233)	(62)	—	(6)	(1,971)	(99)
Sales	—	(43)	(43)	—	—	—	—	—	—	(43)	—
End of 2006	3,414	9,027	12,441	3,310	2,852	3,569	1,087	98	89	23,446	3,389
Revisions	120	446	566	(41)	91	(47)	(26)	—	(12)	531	(327)
Improved recovery	5	1	6	—	—	—	—	—	—	6	—
Purchases	—	30	30	—	—	—	—	—	—	30	—
Extensions and discoveries	5	539	544	143	29	28	23	—	—	767	364
Production	(113)	(835)	(948)	(404)	(369)	(224)	(55)	—	(7)	(2,007)	(103)
Sales	—	(5)	(5)	(170)	(20)	(74)	—	—	(5)	(274)	(384)
End of 2007	3,431	9,203	12,634	2,838	2,583	3,252	1,029	98	65	22,499	2,939
Revisions	(852)	(270)	(1,122)	45	119	249	19	(1)	—	(691)	1,394
Improved recovery	15	2	17	—	—	—	—	—	—	17	—
Purchases	—	13	13	—	—	—	—	—	—	13	598
Extensions and discoveries	2	273	275	118	45	3	—	—	—	441	37
Production	(108)	(788)	(896)	(385)	(391)	(249)	(51)	—	(5)	(1,977)	(118)
Sales	—	(1)	(1)	(2)	(53)	(17)	—	(9)	(60)	(142)	(62)
End of 2008	2,488	8,432	10,920	2,614	2,303	3,238	997	88	—	20,160	4,788
Equity affiliates											
End of 2005	—	—	—	—	—	—	1,063	1,197	288	—	2,548
End of 2006	—	—	—	—	—	—	1,573	1,429	387	—	3,389
End of 2007	—	—	—	—	—	—	1,925	1,014	—	—	2,939
End of 2008	—	—	—	—	—	594	1,925	2,269	—	—	4,788
Developed											
Consolidated operations											
End of 2005	3,316	3,966	7,282	918	2,393	2,600	1,060	—	—	14,253	—
End of 2006	3,336	7,484	10,820	2,672	2,314	3,105	1,029	—	24	19,964	—
End of 2007	3,344	7,417	10,761	2,328	2,177	2,857	963	—	26	19,112	—
End of 2008	2,413	6,875	9,288	2,272	2,036	2,877	936	—	—	17,409	—
Equity affiliates											
End of 2005	—	—	—	—	—	—	—	581	155	—	736
End of 2006	—	—	—	—	—	—	—	655	173	—	828
End of 2007	—	—	—	—	—	—	—	698	—	—	698
End of 2008	—	—	—	—	—	361	—	1,458	—	—	1,819

Natural gas production in the reserves table may differ from gas production (delivered for sale) in our statistics disclosure, primarily because the quantities above include gas consumed at the lease, but omit the gas equivalent of liquids extracted at any of our owned, equity-affiliate, or third-party processing plants or facilities.

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

Notable changes in proved natural gas reserves in the three years ended December 31, 2008, included:

- *Revisions:* In 2008, revisions in Alaska were mainly due to lower prices at December 31, 2008, compared with December 31, 2007. For our equity affiliate operations, revisions primarily resulted from a revised assessment of the reasonable certainty of project development and of the marketability of uncontracted gas volumes.
- *Purchases:* In 2008 for our equity affiliate operations, purchases relate to our Australia Pacific LNG joint venture with Origin Energy. In 2006 for our consolidated operations, purchases were primarily related to our acquisition of Burlington Resources.
- *Extensions and Discoveries:* In 2006 for our equity affiliate operations, extensions and discoveries were primarily in Qatar and LUKOIL.

Years Ended December 31	Natural Gas Liquids										
	Millions of Barrels										
	Consolidated Operations										
	Alaska	Lower 48	Total U.S.	Canada	Europe	Asia Pacific	Middle East and Africa	Russia and Caspian	Other Areas	Total	Equity Affiliates
Developed and Undeveloped											
End of 2005	146	108	254	24	50	71	3	—	—	402	21
Revisions	(1)	24	23	1	(4)	(1)	(1)	—	—	18	—
Improved recovery	—	—	—	—	—	—	—	—	—	—	—
Purchases	—	328	328	56	—	—	—	—	—	384	—
Extensions and discoveries	—	14	14	7	—	—	—	—	—	21	11
Production	(6)	(22)	(28)	(9)	(5)	(7)	—	—	—	(49)	—
Sales	—	(2)	(2)	—	—	—	—	—	—	(2)	—
End of 2006	139	450	589	79	41	63	2	—	—	774	32
Revisions	1	31	32	(4)	—	(2)	—	—	—	26	20
Improved recovery	—	—	—	—	—	—	—	—	—	—	—
Purchases	—	—	—	—	—	—	—	—	—	—	—
Extensions and discoveries	—	12	12	2	1	3	—	—	—	18	7
Production	(7)	(27)	(34)	(10)	(4)	(5)	(1)	—	—	(54)	—
Sales	—	—	—	(2)	—	(3)	—	—	—	(5)	—
End of 2007	133	466	599	65	38	56	1	—	—	759	59
Revisions	(17)	23	6	2	1	(1)	1	—	—	9	—
Improved recovery	—	—	—	—	—	—	—	—	—	—	—
Purchases	—	—	—	—	—	—	—	—	—	—	—
Extensions and discoveries	—	4	4	2	—	—	—	—	—	6	1
Production	(6)	(28)	(34)	(9)	(7)	(6)	(1)	—	—	(57)	—
Sales	—	—	—	—	—	—	—	—	—	—	—
End of 2008	110	465	575	60	32	49	1	—	—	717	60
Equity affiliates											
End of 2005	—	—	—	—	—	—	21	—	—	—	21
End of 2006	—	—	—	—	—	—	32	—	—	—	32
End of 2007	—	—	—	—	—	—	39	20	—	—	59
End of 2008	—	—	—	—	—	—	39	21	—	—	60
Developed											
Consolidated operations											
End of 2005	146	106	252	23	31	64	2	—	—	372	—
End of 2006	139	346	485	64	28	56	2	—	—	635	—
End of 2007	133	343	476	53	33	54	1	—	—	617	—
End of 2008	110	345	455	53	26	47	1	—	—	582	—
Equity affiliates											
End of 2005	—	—	—	—	—	—	—	—	—	—	—
End of 2006	—	—	—	—	—	—	—	—	—	—	—
End of 2007	—	—	—	—	—	—	—	18	—	—	18
End of 2008	—	—	—	—	—	—	—	17	—	—	17

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

Notable changes in proved natural gas liquids reserves in the three years ended December 31, 2008, included:

- *Purchases:* In 2006 for our consolidated operations, purchases were related to our acquisition of Burlington Resources.

Results of Operations

Years Ended December 31	Millions of Dollars										
	Consolidated Operations										
	Alaska	Lower 48	Total U.S.	Canada	Europe	Asia Pacific	Middle East and Africa	Russia and Caspian	Other Areas	Total	Equity Affiliates
2008											
Sales	$5,771	6,726	12,497	4,386	8,061	4,787	1,895	—	290	31,916	6,104
Transfers	3,444	3,401	6,845	—	3,415	579	849	—	—	11,688	3,952
Other revenues	(25)	98	73	317	477	40	230	(56)	40	1,121	88
Total revenues	9,190	10,225	19,415	4,703	11,953	5,406	2,974	(56)	330	44,725	10,144
Production costs excluding taxes	960	1,405	2,365	887	1,157	436	257	—	34	5,136	955
Taxes other than income taxes	3,432	764	4,196	61	29	294	28	(1)	208	4,815	5,218
Exploration expenses	99	469	568	240	235	128	61	41	66	1,339	89
Depreciation, depletion and amortization	559	2,426	2,985	1,802	1,917	733	215	2	24	7,678	630
Impairments*	—	620	620	92	72	9	—	—	—	793	6,666
Transportation costs	409	519	928	140	302	115	29	—	10	1,524	1,010
Other related expenses	(38)	108	70	56	(306)	70	29	60	11	(10)	10
Accretion	40	59	99	33	196	14	4	3	—	349	4
	3,729	3,855	7,584	1,392	8,351	3,607	2,351	(161)	(23)	23,101	(4,438)
Provision for income taxes	1,317	1,310	2,627	371	5,241	1,640	2,094	(25)	(14)	11,934	633
Results of operations for producing activities	2,412	2,545	4,957	1,021	3,110	1,967	257	(136)	(9)	11,167	(5,071)
Other earnings	(97)	128	31	243	314	82	(71)	80	(25)	654	(274)
Net income (loss)	$2,315	2,673	4,988	1,264	3,424	2,049	186	(56)	(34)	11,821	(5,345)
Results of operations for producing activities of equity affiliates	$ —	—	—	286	—	4	(3)	(5,357)	(1)	—	(5,071)

**Excludes goodwill impairment of $25,443 million.*

2007											
Sales*	$4,659	5,422	10,081	3,406	5,701	3,383	1,538	—	240	24,349	5,212
Transfers*	2,344	2,986	5,330	—	2,729	267	657	—	—	8,983	3,427
Other revenues	173	94	267	430	330	252	201	1	3	1,484	71
Total revenues	7,176	8,502	15,678	3,836	8,760	3,902	2,396	1	243	34,816	8,710
Production costs excluding taxes	775	1,232	2,007	874	1,029	410	251	—	41	4,612	906
Taxes other than income taxes	1,663	628	2,291	70	45	129	18	2	98	2,653	3,675
Exploration expenses	104	318	422	247	105	130	77	24	12	1,017	68
Depreciation, depletion and amortization	583	2,559	3,142	1,661	1,394	608	204	—	—	7,009	551
Impairments**	28	43	71	27	188	26	—	—	918	1,230	3,825
Transportation costs	412	553	965	137	335	101	24	—	64	1,626	770
Other related expenses	(64)	72	8	(96)	46	(26)	34	56	37	59	57
Accretion	37	48	85	47	132	9	3	1	—	277	7
	3,638	3,049	6,687	869	5,486	2,515	1,785	(82)	(927)	16,333	(1,149)
Provision for income taxes	1,248	1,091	2,339	237	3,595	982	1,545	(28)	1	8,671	844
Results of operations for producing activities	2,390	1,958	4,348	632	1,891	1,533	240	(54)	(928)	7,662	(1,993)
Other earnings	(135)	35	(100)	280	48	67	25	33	197	550	214
Net income (loss)	$2,255	1,993	4,248	912	1,939	1,600	265	(21)	(731)	8,212	(1,779)
Results of operations for producing activities of equity affiliates	$ —	—	—	98	—	—	(5)	1,554	(3,640)	—	(1,993)

**Certain amounts in the Middle East and Africa were reclassified between "sales" and "transfers." Total revenues were unchanged.*

***Restated to align the portion of the expropriated assets impairment associated with Hamaca and Petrozuata from consolidated operations to equity affiliates.*

Year Ended December 31	Millions of Dollars										
	Consolidated Operations										
	Alaska	Lower 48	Total U.S.	Canada	Europe	Asia Pacific	Middle East and Africa	Russia and Caspian	Other Areas	Total	Equity Affiliates
2006											
Sales*	$4,491	4,881	9,372	2,951	5,950	3,493	2,224	—	140	24,130	5,161
Transfers*	2,023	2,550	4,573	—	2,954	271	283	—	—	8,081	2,821
Other revenues	2	56	58	145	14	(8)	127	—	4	340	108
Total revenues	6,516	7,487	14,003	3,096	8,918	3,756	2,634	—	144	32,551	8,090
Production costs excluding taxes	708	893	1,601	706	814	324	215	—	27	3,687	739
Taxes other than income taxes	914	554	1,468	52	37	91	10	1	30	1,689	3,444
Exploration expenses	105	222	327	246	73	121	44	32	17	860	46
Depreciation, depletion and amortization	460	2,272	2,732	1,155	1,200	512	220	1	21	5,841	461
Impairments	—	15	15	131	—	10	—	—	19	175	—
Transportation costs	610	555	1,165	104	316	89	18	—	10	1,702	420
Other related expenses	11	44	55	15	87	18	38	43	28	284	52
Accretion	34	36	70	39	97	8	2	—	—	216	6
	3,674	2,896	6,570	648	6,294	2,583	2,087	(77)	(8)	18,097	2,922
Provision for income taxes	1,409	1,064	2,473	(193)	4,578	1,061	1,931	(13)	(7)	9,830	891
Results of operations for producing activities	2,265	1,832	4,097	841	1,716	1,522	156	(64)	(1)	8,267	2,031
Other earnings	82	169	251	191	335	62	32	(4)	(25)	842	133
Net income (loss)	$2,347	2,001	4,348	1,032	2,051	1,584	188	(68)	(26)	9,109	2,164
Results of operations for producing activities of equity affiliates	$ —	—	—	—	—	—	(6)	1,229	808	—	2,031

**Certain amounts in the Middle East and Africa were reclassified between "sales" and "transfers." Total revenues were unchanged.*

- Results of operations for producing activities consist of all activities within the E&P organization and producing activities within the LUKOIL Investment segment, except for pipeline and marine operations, liquefied natural gas operations, our Canadian Syncrude operation, and crude oil and gas marketing activities, which are included in other earnings. Also excluded are our Midstream segment, downstream petroleum and chemical activities, as well as general corporate administrative expenses and interest.
- Transfers are valued at prices that approximate market.
- Other revenues include gains and losses from asset sales, certain amounts resulting from the purchase and sale of hydrocarbons, and other miscellaneous income.
- Production costs are those incurred to operate and maintain wells and related equipment and facilities used to produce petroleum liquids and natural gas. These costs also include depreciation of support equipment and administrative expenses related to the production activity.
- Taxes other than income taxes include production, property and other non-income taxes.
- Exploration expenses include dry hole costs, leasehold impairments, geological and geophysical expenses, the costs of retaining undeveloped leaseholds, and depreciation of support equipment and administrative expenses related to the exploration activity.
- Depreciation, depletion and amortization (DD&A) in Results of Operations differs from that shown for total E&P in Note 26 — Segment Disclosures and Related Information, in the Notes to Consolidated Financial Statements, mainly due to depreciation of support equipment being reclassified to production or exploration expenses, as applicable, in Results of Operations. In addition, other earnings include certain E&P activities, including their related DD&A charges.
- Transportation costs include costs to transport our produced oil, natural gas or natural gas liquids to their points of sale, as well as processing fees paid to process natural gas to natural gas liquids. The profit element of transportation operations in which we have an ownership interest are deemed to be outside oil and gas producing activities. The net income of the transportation operations is included in other earnings.
- Other related expenses include foreign currency transaction gains and losses, and other miscellaneous expenses.
- The provision for income taxes is computed by adjusting each country's income before income taxes for permanent differences related to oil and gas producing activities that are reflected in our consolidated income tax expense for the period, multiplying the result by the country's statutory tax rate, and adjusting for applicable tax credits. Included in 2007 for Canada is a benefit related to the remeasurement of deferred tax liabilities from the 2007 Canadian graduated tax rate reduction. Included in 2006 for Canada is a $353 million benefit (which excludes $48 million related to the Syncrude oil project reflected in other earnings) related to the remeasurement of deferred tax liabilities from the 2006 Canadian graduated tax rate reduction and an Alberta provincial tax rate change. Europe income tax expense for 2006 was increased $250 million due to remeasurement of deferred tax liabilities as a result of increases in the U.K. tax rate.

Statistics

Net Production	2008	2007	2006
	Thousands of Barrels Daily		
Crude Oil			
Consolidated operations			
Alaska	**244**	261	263
Lower 48	**91**	102	104
United States	**335**	363	367
Canada	**25**	19	25
Europe	**214**	210	245
Asia Pacific	**91**	87	106
Middle East and Africa	**78**	81	106
Other areas	**9**	10	7
Total consolidated	**752**	770	856
Equity affiliates			
Canada	**30**	27	—
Russia and Caspian	**410**	416	375
Other areas	**—**	42	101
Total equity affiliates	**440**	485	476
Natural Gas Liquids*			
Consolidated operations			
Alaska	**17**	19	17
Lower 48	**74**	79	62
United States	**91**	98	79
Canada	**25**	27	25
Europe	**19**	14	13
Asia Pacific	**16**	14	18
Middle East and Africa	**2**	2	1
Total consolidated	**153**	155	136

**Represents amounts extracted attributable to E&P operations (see natural gas liquids reserves for further discussion). Includes for 2008, 2007 and 2006, 11,000, 14,000, and 11,000 barrels daily in Alaska, respectively, that were sold from the Prudhoe Bay lease to the Kuparuk lease for re-injection to enhance crude oil production.*

	Millions of Cubic Feet Daily		
Natural Gas*			
Consolidated operations			
Alaska	**97**	110	145
Lower 48	**1,994**	2,182	2,028
United States	**2,091**	2,292	2,173
Canada	**1,054**	1,106	983
Europe	**954**	961	1,065
Asia Pacific	**609**	579	582
Middle East and Africa	**114**	125	142
Other areas	**14**	19	16
Total consolidated	**4,836**	5,082	4,961
Equity affiliates			
Russia and Caspian	**356**	256	244
Asia Pacific	**11**	—	—
Other areas	**—**	5	9
Total equity affiliates	**367**	261	253

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

Average Sales Price	2008	2007	2006
Crude Oil			
Per Barrel			
Consolidated operations			
Alaska	**$ 99.23**	69.75	62.66
Lower 48	**92.77**	63.49	57.04
United States	**97.47**	68.00	61.09
Canada	**80.18**	61.77	54.25
Europe	**95.73**	71.81	64.05
Asia Pacific	**91.47**	70.23	61.93
Middle East and Africa	**93.98**	72.18	66.59
Other areas	**84.74**	60.84	50.63
Total international	**93.30**	70.79	63.38
Total consolidated	**95.15**	69.47	62.39
Equity affiliates			
Canada	**58.54**	37.94	—
Russia and Caspian	**61.48**	50.00	41.61
Other areas	**—**	47.46	46.40
Total equity affiliates	**61.28**	49.13	42.66
Natural Gas Liquids			
Per Barrel			
Consolidated operations			
Alaska	**$ 94.29**	71.85	61.06
Lower 48	**52.28**	44.43	38.10
United States	**55.63**	46.00	40.35
Canada	**66.40**	50.85	45.62
Europe	**53.33**	45.72	38.78
Asia Pacific	**64.30**	53.19	43.95
Middle East and Africa	**8.51**	8.31	8.15
Total international	**59.70**	48.80	42.89
Total consolidated	**57.43**	47.13	41.50
Natural Gas			
Per Thousand Cubic Feet			
Consolidated operations			
Alaska	**$ 4.38**	3.68	3.59
Lower 48	**7.71**	5.99	6.14
United States	**7.67**	5.98	6.11
Canada	**7.92**	6.09	5.67
Europe	**10.55**	7.87	7.78
Asia Pacific	**9.10**	6.37	5.91
Middle East and Africa	**1.09**	.80	.70
Other areas	**1.41**	1.18	1.31
Total international	**8.76**	6.51	6.27
Total consolidated	**8.28**	6.26	6.20
Equity affiliates			
Russia and Caspian	**1.06**	1.02	.57
Asia Pacific	**2.04**	—	—
Other areas	**—**	.30	.30
Total equity affiliates	**1.10**	1.01	.57
Average Production Costs			
Per Barrel of Oil Equivalent			
Consolidated operations			
Alaska	**$ 9.46**	7.12	6.38
Lower 48	**7.72**	6.20	4.85
United States	**8.34**	6.52	5.43
Canada	**10.74**	10.40	9.05
Europe	**8.06**	7.34	5.12
Asia Pacific	**5.71**	5.69	4.02
Middle East and Africa	**7.09**	6.62	4.51
Other areas	**8.20**	8.53	7.65
Total international	**8.08**	7.68	5.65
Total consolidated	**8.20**	7.13	5.55
Equity affiliates			
Canada	**16.58**	13.32	—
Russia and Caspian	**4.46**	4.04	3.53
Asia Pacific	**5.96**	—	—
Other areas	**—**	6.24	5.42
Total equity affiliates	**5.21**	4.70	3.91

Taxes Other Than Income Taxes Per Barrel of Oil Equivalent	2008	2007	2006
Consolidated operations			
Alaska	**$ 33.83**	15.27	8.23
Lower 48	**4.20**	3.16	3.01
United States	**14.80**	7.45	4.98
Canada	**.74**	.83	.67
Europe	**.20**	.32	.23
Asia Pacific	**3.85**	1.79	1.13
Middle East and Africa	**.77**	.47	.21
Other areas	**50.14**	20.39	8.50
Total international	**1.81**	1.07	.60
Total consolidated	**7.69**	4.10	2.54
Equity affiliates			
Canada	**.27**	.21	—
Russia and Caspian	**30.36**	20.89	21.40
Other areas	**—**	11.21	5.28
Total equity affiliates	**28.45**	19.05	18.21

Depreciation, Depletion and Amortization Per Barrel of Oil Equivalent	2008	2007	2006
Consolidated operations			
Alaska	**$ 5.51**	5.35	4.14
Lower 48	**13.33**	12.87	12.35
United States	**10.53**	10.21	9.26
Canada	**21.82**	19.76	14.80
Europe	**13.36**	9.94	7.55
Asia Pacific	**9.61**	8.43	6.35
Middle East and Africa	**5.93**	5.38	4.61
Other areas	**5.79**	—	5.95
Total international	**13.69**	11.40	8.43
Total consolidated	**12.26**	10.84	8.80
Equity affiliates			
Canada	**7.65**	6.82	—
Russia and Caspian	**3.13**	2.53	2.04
Asia Pacific	**13.41**	—	—
Other areas	**—**	3.88	4.04
Total equity affiliates	**3.43**	2.86	2.43

Acreage at December 31, 2008	Thousands of Acres			
	Developed		Undeveloped	
	Gross	Net	Gross	Net
Consolidated operations				
Alaska	647	328	2,900	2,036
Lower 48	7,887	5,487	13,384	9,691
United States	8,534	5,815	16,284	11,727
Canada	7,085	4,513	10,891	7,316
Europe	1,081	311	4,100	1,635
Asia Pacific	4,212	1,817	32,253	21,649
Middle East and Africa	2,466	449	12,790	2,258
Russia and Caspian	—	—	1,379	116
Other areas	1,001	444	11,561	9,517
Total consolidated	24,379	13,349	89,258	54,218
Equity affiliates				
Canada	57	25	483	193
Middle East and Africa	—	—	76	11
Russia and Caspian	290	90	1,175	476
Asia Pacific	178	50	10,088	3,948
Total equity affiliates*	525	165	11,822	4,628

**Excludes LUKOIL.*

Net Wells Completed[1]	Productive			Dry		
	2008	2007	2006	2008	2007	2006
Exploratory[2]						
Consolidated operations						
Alaska	—	3	—	**1**	1	1
Lower 48	**81**	71	27	**22**	9	9
United States	**81**	74	27	**23**	10	10
Canada	**49**	50	8	**36**	17	7
Europe	*	1	1	**1**	1	1
Asia Pacific	**1**	4	2	*	1	2
Middle East and Africa	*	—	1	**1**	1	1
Russia and Caspian	—	—	—	—	*	—
Other areas	—	—	1	**1**	—	*
Total consolidated	**131**	129	40	**62**	30	21
Equity affiliates						
Middle East and Africa	—	—	*	—	—	—
Russia and Caspian	**1**	—	—	**1**	—	1
Asia Pacific	—	—	—	*	—	—
Total equity affiliates[3]	**1**	—	*	**1**	—	1
Includes step-out wells of:	***127***	*99*	*37*	***27***	*18*	*11*
Development						
Consolidated operations						
Alaska	**47**	46	30	—	—	1
Lower 48	**690**	686	659	**8**	7	3
United States	**737**	732	689	**8**	7	4
Canada**	**465**	326	649	**32**	23	34
Europe	**10**	10	10	—	—	—
Asia Pacific	**26**	17	15	—	—	—
Middle East and Africa	**4**	7	7	—	*	—
Russia and Caspian	—	*	*	—	—	—
Other areas	—	5	11	—	—	—
Total consolidated	**1,242**	1,097	1,381	**40**	30	38
Equity affiliates						
Canada	**148**	70	—	—	1	—
Russia and Caspian	**7**	2	2	—	—	1
Asia Pacific	*	—	—	—	—	—
Other areas	—	—	15	—	—	—
Total equity affiliates[3]	**155**	72	17	—	1	1

[1] Excludes farmout arrangements.
[2] Includes step-out wells, as well as other types of exploratory wells. Step-out exploratory wells are wells drilled in areas near or offsetting current production, for which we cannot demonstrate with certainty that there is continuity of production from an existing productive formation. These are classified as exploratory wells because we cannot attribute proved reserves to these locations.
[3] Excludes LUKOIL.
**Our total proportionate interest was less than one.*
***Certain wells in 2007 and 2006 were reclassified from productive to dry.*

Wells at Year-End 2008	In Progress[1]		Productive[2]			
			Oil		Gas	
	Gross	Net	Gross	Net	Gross	Net
Consolidated operations						
Alaska	24	13	1,941	869	29	19
Lower 48	524	350	12,846	5,030	25,616	16,614
United States	548	363	14,787	5,899	25,645	16,633
Canada	220[3]	154[3]	1,890	1,036	11,693	6,737
Europe	41	10	592	104	268	108
Asia Pacific	116	51	378	144	79	38
Middle East and Africa	36	6	1,086	193	—	—
Russia and Caspian	30	3	—	—	—	—
Other areas	3	1	93	41	—	—
Total consolidated	994	588	18,826	7,417	37,685	23,516
Equity affiliates						
Canada	16	8	133	66	6	3
Russia and Caspian	12	4	83	30	2	1
Asia Pacific	311	89	—	—	389	119
Middle East and Africa	34	5	—	—	—	—
Total equity affiliates[4]	373	106	216	96	397	123

[1] Includes wells that have been temporarily suspended.
[2] Includes 5,748 gross and 3,645 net multiple completion wells.
[3] Includes 154 gross and 116 net stratigraphic test wells related to heavy-oil projects.
[4] Excludes LUKOIL.

Costs Incurred

	Millions of Dollars										
	Consolidated Operations										
	Alaska	Lower 48	Total U.S.	Canada	Europe	Asia Pacific	Middle East and Africa	Russia and Caspian	Other Areas	Total	Equity Affiliates
2008											
Unproved property acquisition	$ 514	505	1,019	195	—	5	—	—	—	1,219	4,544
Proved property acquisition	—	37	37	—	—	—	—	—	—	37	282
	514	542	1,056	195	—	5	—	—	—	1,256	4,826
Exploration	124	733	857	219	279	213	53	43	54	1,718	160
Development	823	2,458	3,281	1,387	2,056	1,314	175	612	7	8,832	2,625
	$1,461	3,733	5,194	1,801	2,335	1,532	228	655	61	11,806	7,611
Costs incurred of equity affiliates	$ —	—	—	576	—	4,775	194	2,066	—	—	7,611
2007*											
Unproved property acquisition	$ 5	202	207	117	—	122	—	—	—	446	2,135
Proved property acquisition	—	42	42	—	—	—	—	—	—	42	1,810
	5	244	249	117	—	122	—	—	—	488	3,945
Exploration	115	468	583	196	235	147	73	37	21	1,292	144
Development	567	2,375	2,942	1,252	1,871	1,275	355	462	73	8,230	2,506
	$ 687	3,087	3,774	1,565	2,106	1,544	428	499	94	10,010	6,595
Costs incurred of equity affiliates	$ —	—	—	4,117	—	—	334	2,093	51	—	6,595
2006											
Unproved property acquisition	$ 4	860	864	554	113	—	30	—	39	1,600	143
Proved property acquisition	13	15,784	15,797	8,296	1,169	525	856	—	252	26,895	2,647
	17	16,644	16,661	8,850	1,282	525	886	—	291	28,495	2,790
Exploration	131	332	463	182	172	231	57	47	27	1,179	58
Development	629	1,733	2,362	1,926	1,653	919	249	371	141	7,621	1,326
	$ 777	18,709	19,486	10,958	3,107	1,675	1,192	418	459	37,295	4,174
Costs incurred of equity affiliates	$ —	—	—	—	—	—	183	3,854	137	—	4,174

**Restated to include amounts omitted from equity affiliates in 2007 and to align certain amounts in the Middle East and Africa from consolidated operations to equity affiliates.*

- Costs incurred include capitalized and expensed items.
- Acquisition costs include the costs of acquiring proved and unproved oil and gas properties. In 2008, equity affiliate acquisition costs were due to the Australia Pacific LNG joint venture with Origin Energy. In 2007, equity affiliate acquisition costs were due to the FCCL business venture with EnCana. For 2006 consolidated operations, acquisition costs were primarily related to the Burlington Resources acquisition.
- Exploration costs include geological and geophysical expenses, the cost of retaining undeveloped leaseholds, and exploratory drilling costs.
- Development costs include the cost of drilling and equipping development wells and building related production facilities for extracting, treating, gathering and storing petroleum liquids and natural gas.

Capitalized Costs

At December 31	Millions of Dollars										
	Consolidated Operations										
	Alaska	Lower 48	Total U.S.	Canada	Europe	Asia Pacific	Middle East and Africa	Russia and Caspian	Other Areas	Total	Equity Affiliates*
2008											
Proved properties	$10,880	31,592	42,472	15,237	17,025	9,269	2,922	2,508	566	89,999	15,361
Unproved properties	1,388	1,541	2,929	1,672	316	825	269	121	60	6,192	7,936
	12,268	33,133	45,401	16,909	17,341	10,094	3,191	2,629	626	96,191	23,297
Accumulated depreciation, depletion and amortization	4,642	10,974	15,616	5,672	8,622	2,810	1,025	5	528	34,278	8,271
	$ 7,626	22,159	29,785	11,237	8,719	7,284	2,166	2,624	98	61,913	15,026
Capitalized costs of equity affiliates	$ —	—	—	4,258	—	5,402	781	4,585	—	—	15,026
2007											
Proved properties	$10,182	28,645	38,827	17,330	20,615	8,014	2,758	2,135	641	90,320	12,707
Unproved properties	848	1,137	1,985	1,798	446	795	281	131	83	5,519	3,515
	11,030	29,782	40,812	19,128	21,061	8,809	3,039	2,266	724	95,839	16,222
Accumulated depreciation, depletion and amortization	4,158	7,920	12,078	4,875	9,374	2,155	822	4	504	29,812	1,008
	$ 6,872	21,862	28,734	14,253	11,687	6,654	2,217	2,262	220	66,027	15,214
Capitalized costs of equity affiliates*	$ —	—	—	4,771	—	—	649	9,794	—	—	15,214

**Restated to include certain amounts that were omitted in 2007.*

- Capitalized costs include the cost of equipment and facilities for oil and gas producing activities. These costs include the activities of our E&P and LUKOIL Investment segments, excluding pipeline and marine operations, liquefied natural gas operations, our Canadian Syncrude operation, crude oil and natural gas marketing activities, and downstream operations.
- Proved properties include capitalized costs for oil and gas leaseholds holding proved reserves, development wells and related equipment and facilities (including uncompleted development well costs), and support equipment.
- Unproved properties include capitalized costs for oil and gas leaseholds under exploration (including where petroleum liquids and natural gas were found but determination of the economic viability of the required infrastructure is dependent upon further exploratory work under way or firmly planned) and for uncompleted exploratory well costs, including exploratory wells under evaluation.

Standardized Measure of Discounted Future Net Cash Flows Relating to Proved Oil and Gas Reserve Quantities

Amounts are computed using year-end prices and costs (adjusted only for existing contractual changes), appropriate statutory tax rates and a prescribed 10 percent discount factor. Continuation of year-end economic conditions also is assumed. The calculation is based on estimates of proved reserves, which are revised over time as new data becomes available. Probable or possible reserves, which may become proved in the future, are not considered. The calculation also requires assumptions as to the timing of future production of proved reserves, and the timing and amount of future development, including dismantlement, and production costs.

While due care was taken in its preparation, we do not represent that this data is the fair value of our oil and gas properties, or a fair estimate of the present value of cash flows to be obtained from their development and production.

Discounted Future Net Cash Flows

	Millions of Dollars										
	Consolidated Operations										
	Alaska	Lower 48	Total U.S.	Canada	Europe	Asia Pacific	Middle East and Africa	Russia and Caspian	Other Areas	Total	Equity Affiliates
2008											
Future cash inflows	$ 54,662	51,354	106,016	19,632	42,230	22,626	11,388	4,200	157	206,249	64,631
Less:											
Future production and transportation costs*	35,150	30,508	65,658	9,357	12,217	6,960	3,567	1,870	130	99,759	48,592
Future development costs	9,681	10,443	20,124	4,188	8,835	2,859	440	2,080	4	38,530	8,821
Future income tax provisions	3,227	3,439	6,666	401	11,679	4,880	6,082	246	2	29,956	891
Future net cash flows	6,604	6,964	13,568	5,686	9,499	7,927	1,299	4	21	38,004	6,327
10 percent annual discount	2,159	2,886	5,045	1,222	3,178	2,998	398	702	1	13,544	3,294
Discounted future net cash flows	$ 4,445	4,078	8,523	4,464	6,321	4,929	901	(698)	20	24,460	3,033
Discounted future net cash flows of equity affiliates	$ —	—	—	79	—	210	1,781	963	—	—	3,033
2007											
Future cash inflows	$133,909	94,706	228,615	30,125	83,367	46,520	31,509	11,272	803	432,211	163,555
Less:											
Future production and transportation costs*	75,024	41,945	116,969	11,206	15,781	11,996	3,884	1,876	706	162,418	97,375
Future development costs	8,392	9,690	18,082	4,605	10,920	3,958	400	2,761	34	40,760	10,847
Future income tax provisions	18,798	14,793	33,591	2,235	37,645	12,331	22,599	1,680	10	110,091	12,381
Future net cash flows	31,695	28,278	59,973	12,079	19,021	18,235	4,626	4,955	53	118,942	42,952
10 percent annual discount	16,510	12,158	28,668	3,870	5,776	7,113	1,847	4,504	2	51,780	22,925
Discounted future net cash flows	$ 15,185	16,120	31,305	8,209	13,245	11,122	2,779	451	51	67,162	20,027
Discounted future net cash flows of equity affiliates	$ —	—	—	3,889	—	—	4,453	11,685	—	—	20,027
2006											
Future cash inflows	$ 86,843	75,039	161,882	25,363	60,118	32,420	19,369	6,853	1,777	307,782	117,860
Less:											
Future production and transportation costs*	43,393	23,096	66,489	9,393	13,186	6,730	4,308	1,692	1,082	102,880	66,929
Future development costs	5,142	7,274	12,416	4,154	7,865	2,886	586	2,787	220	30,914	6,369
Future income tax provisions	14,138	14,357	28,495	2,313	25,627	9,204	12,029	590	101	78,359	16,085
Future net cash flows	24,170	30,312	54,482	9,503	13,440	13,600	2,446	1,784	374	95,629	28,477
10 percent annual discount	12,479	15,697	28,176	3,297	4,052	5,482	753	2,213	66	44,039	16,044
Discounted future net cash flows	$ 11,691	14,615	26,306	6,206	9,388	8,118	1,693	(429)	308	51,590	12,433
Discounted future net cash flows of equity affiliates	$ —	—	—	—	—	—	1,703	5,441	5,289	—	12,433

**Includes taxes other than income taxes.*

Excludes discounted future net cash flows from Canadian Syncrude of $435 million in 2008, $4,484 million in 2007 and $2,220 million in 2006.

Sources of Change in Discounted Future Net Cash Flows

	Millions of Dollars					
	Consolidated Operations			Equity Affiliates		
	2008	2007	2006	**2008**	2007	2006
Discounted future net cash flows at the beginning of the year	**$ 67,162**	51,590	53,948	**20,027**	12,433	16,659
Changes during the year						
Revenues less production and transportation costs for the year*	**(32,129)**	(24,441)	(25,133)	**(2,873)**	(3,288)	(3,379)
Net change in prices, and production and transportation costs*	**(73,497)**	49,447	(18,928)	**(22,541)**	10,082	(5,582)
Extensions, discoveries and improved recovery, less estimated future costs	**1,743**	6,985	3,867	**181**	2,188	401
Development costs for the year	**7,715**	7,289	7,020	**2,622**	2,346	1,327
Changes in estimated future development costs	**(3,129)**	(10,813)	(6,195)	**(813)**	(3,468)	(1,291)
Purchases of reserves in place, less estimated future costs	**10**	51	24,203	**321**	2,989	1,945
Sales of reserves in place, less estimated future costs	**(52)**	(1,347)	(506)	**(33)**	(9,619)	2
Revisions of previous quantity estimates**	**1,893**	(79)	(7,028)	**(1,689)**	3,855	107
Accretion of discount	**11,765**	8,561	9,759	**2,456**	1,809	2,215
Net change in income taxes	**42,979**	(20,081)	10,583	**5,375**	700	29
Total changes	**(42,702)**	15,572	(2,358)	**(16,994)**	7,594	(4,226)
Discounted future net cash flows at year end	**$ 24,460**	67,162	51,590	**3,033**	20,027	12,433

**Includes taxes other than income taxes.*
***Includes amounts resulting from changes in the timing of production.*

- The net change in prices, and production and transportation costs is the beginning-of-year reserve-production forecast multiplied by the net annual change in the per-unit sales price, and production and transportation cost, discounted at 10 percent.
- Purchases and sales of reserves in place, along with extensions, discoveries and improved recovery, are calculated using production forecasts of the applicable reserve quantities for the year multiplied by the end-of-year sales prices, less future estimated costs, discounted at 10 percent.
- The accretion of discount is 10 percent of the prior year's discounted future cash inflows, less future production, transportation and development costs.
- The net change in income taxes is the annual change in the discounted future income tax provisions.

5-Year Financial Review (Millions of Dollars Except as Indicated)

	2008	2007	2006	2005	2004
Selected Income Data					
Sales and other operating revenues	**$ 240,842**	187,437	183,650	179,442	135,076
Total revenues and other income	**$ 246,182**	194,495	188,523	183,364	136,916
Income (loss) from continuing operations	**$ (16,998)**	11,891	15,550	13,640	8,107
Effective income tax rate	**(373.1)%**	48.9	45.1	42.1	43.6
Net income (loss)	**$ (16,998)**	11,891	15,550	13,529	8,129
Selected Balance Sheet Data					
Current assets	**$ 20,843**	24,735	25,066	19,612	15,021
Net properties, plants and equipment	**$ 83,947**	89,003	86,201	54,669	50,902
Goodwill	**$ 3,778**	29,336	31,488	15,323	14,990
Total assets	**$ 142,865**	177,757	164,781	106,999	92,861
Current liabilities	**$ 21,780**	26,882	26,431	21,359	15,586
Long-term debt	**$ 27,085**	20,289	23,091	10,758	14,370
Total debt	**$ 27,455**	21,687	27,134	12,516	15,002
Joint venture acquisition obligation — related party	**$ 5,669**	6,294	—	—	—
Minority interests	**$ 1,100**	1,173	1,202	1,209	1,105
Common stockholders' equity	**$ 55,165**	88,983	82,646	52,731	42,723
Percent of total debt to capital*	**33%**	19	24	19	26
Selected Statement of Cash Flows Data					
Net cash provided by operating activities from continuing operations	**$ 22,658**	24,550	21,516	17,633	11,998
Net cash provided by operating activities	**$ 22,658**	24,550	21,516	17,628	11,959
Capital expenditures and investments	**$ 19,099**	11,791	15,596	11,620	9,496
Proceeds from asset dispositions	**$ 1,640**	3,572	545	768	1,591
Repurchase of company common stock	**$ 8,249**	7,001	925	1,924	—
Cash dividends paid on common stock	**$ 2,854**	2,661	2,277	1,639	1,232
Other Data					
Per average common share outstanding					
Income (loss) from continuing operations					
Basic	**$ (11.16)**	7.32	9.80	9.79	5.87
Diluted	**$ (11.16)**	7.22	9.66	9.63	5.79
Net income (loss)					
Basic	**$ (11.16)**	7.32	9.80	9.71	5.88
Diluted	**$ (11.16)**	7.22	9.66	9.55	5.80
Cash dividends declared per common share	**$ 1.88**	1.64	1.44	1.18	.895
Common shares outstanding at year end (in millions)	**1,480.2**	1,571.4	1,646.1	1,377.8	1,389.5
Average common shares outstanding (in millions)					
Basic	**1,523.4**	1,624.0	1,586.0	1,393.4	1,381.6
Diluted	**1,523.4**	1,645.9	1,609.5	1,417.0	1,401.3
Employees at year end (in thousands)	**33.8**	32.6	38.4	35.6	35.8

Capital includes total debt, minority interests and common stockholders' equity.

5-Year Operating Review

E&P	2008	2007	2006	2005	2004
	Thousands of Barrels Daily (MBD)				
Crude Oil Production					
United States	**335**	363	367	353	349
Europe	**214**	210	245	257	271
Asia Pacific	**91**	87	106	100	94
Canada	**25**	19	25	23	25
Middle East and Africa	**78**	81	106	53	58
Other areas	**9**	10	7	—	—
Total consolidated	**752**	770	856	786	797
Equity affiliates	**54**	84	116	121	108
	806	854	972	907	905
Natural Gas Liquids Production					
United States	**91**	98	79	50	49
Europe	**19**	14	13	13	14
Asia Pacific	**16**	14	18	16	9
Canada	**25**	27	25	10	10
Middle East and Africa	**2**	2	1	2	2
	153	155	136	91	84
	Millions of Cubic Feet Daily (MMCFD)				
Natural Gas Production*					
United States	**2,091**	2,292	2,173	1,381	1,388
Europe	**954**	961	1,065	1,023	1,119
Asia Pacific	**609**	579	582	350	301
Canada	**1,054**	1,106	983	425	433
Middle East and Africa	**114**	125	142	84	71
Other areas	**14**	19	16	—	—
Total consolidated	**4,836**	5,082	4,961	3,263	3,312
Equity affiliates	**11**	5	9	7	5
	4,847	5,087	4,970	3,270	3,317

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

	Thousands of Barrels Daily				
Syncrude Production	**22**	23	21	19	21
Midstream					
Natural Gas Liquids Extracted*	**188**	211	209	195	194

Includes our share of equity affiliates.

R&M					
Refinery Operations*					
United States					
Crude oil capacity**	**2,008**	2,035	2,208	2,180	2,164
Crude oil runs	**1,849**	1,944	2,025	1,996	2,059
Refinery production	**2,035**	2,146	2,213	2,186	2,245
International					
Crude oil capacity**	**670**	687	651	428	437
Crude oil runs	**567**	616	591	424	396
Refinery production	**575**	633	618	439	405
Petroleum Products Sales					
United States					
Gasoline	**1,128**	1,244	1,336	1,374	1,356
Distillates	**893**	872	850	876	744
Other products	**374**	432	531	519	564
	2,395	2,548	2,717	2,769	2,664
International	**645**	697	759	482	477
	3,040	3,245	3,476	3,251	3,141

Includes our share of equity affiliates, except for our share of LUKOIL, which is reported in the LUKOIL Investment segment.
**Weighted-average crude oil capacity for the period.*

LUKOIL Investment*					
Crude oil production (MBD)	**386**	401	360	235	38
Natural gas production (MMCFD)	**356**	256	244	67	13
Refinery crude processed (MBD)	**229**	214	179	122	19

Represents our net share of our estimate of LUKOIL's production and processing.

Board of Directors

Richard L. Armitage, 63, president of Armitage International LLC since 2005. U.S. Deputy Secretary of State from 2001 to 2005. President of Armitage Associates from 1993 to 2001. Assistant Secretary of Defense for International Security Affairs from 1983 to 1989. Recipient of numerous U.S. and foreign decorations and service awards. Also a director of ManTech International Corporation and Transcu Ltd. Lives in Vienna, Va. (4)

Richard H. Auchinleck, 57, president and CEO of Gulf Canada Resources Limited from 1998 to 2001. Chief operating officer of Gulf Canada and CEO for Gulf Indonesia Resources Limited from 1997 to 1998. Also a director of Enbridge Commercial Trust and Telus Corporation. Lives in Calgary, Alberta, Canada. (2, 4)

James E. Copeland, Jr., 64, CEO of Deloitte & Touche USA, and its parent company, Deloitte & Touche Tohmatsu, from 1999 to 2003. Served as a director of Coca-Cola Enterprises from 2003 to 2008. A director of Equifax since 2003. Also serves as a director for Time Warner Cable Inc. Lives in Duluth, Ga. (1, 2)

Kenneth M. Duberstein, 64, chairman and CEO of the Duberstein Group, a strategic planning and consulting company, since 1989. Served as White House chief of staff and previously as deputy chief of staff to President Ronald Reagan. Also a director of The Boeing Company, The Travelers Companies, Inc. and Mack-Cali Realty Corporation. Lives in Washington, D.C. (5)

Ruth R. Harkin, 64, senior vice president of international affairs and government relations, United Technologies Corporation (UTC) and chair of United Technologies International, UTC's international representation arm, from 1997 to 2005. CEO and president of Overseas Private Investment Corporation from 1993 to 1997. Member of the Iowa state board of regents, and a director of AbitibiBowater Inc. Lives in Alexandria, Va. (2, 5)

Harold McGraw III, 60, chairman, president and CEO of The McGraw-Hill Companies since 2000. President and CEO of The McGraw-Hill Companies from 1998 to 2000. Member of The McGraw-Hill Companies' board of directors since 1987. Also a director of United Technologies Corporation. Lives in Darien, Conn. (3, 4)

James J. Mulva, 62, chairman and CEO of ConocoPhillips. Chairman, president and CEO of Phillips from 1999 to 2002. President and chief operating officer from 1994 to 1999. Joined Phillips in 1973; elected to board in 1994. Served as 2006 chairman of the American Petroleum Institute. A director of General Electric and M.D. Anderson Cancer Center, member of The Business Council and The Business Roundtable, and trustee of the Boys and Girls Clubs of America. (2)

Harald J. Norvik, 62, strategic advisor of Econ Pöyry AS. Chairman, president and CEO of Statoil from 1988 to 1999. Chairman of the board of Telenor ASA and also a director of Petroleum Geo-Services ASA. Lives in Nesoddangen, Norway. (1)

William K. Reilly, 69, president and CEO of Aqua International Partners, an investment group that finances water improvements in developing countries, since 1997. Also a director of E.I. du Pont de Nemours and Company, and Royal Caribbean Cruises Ltd. Lives in San Francisco, Calif. (5)

Bobby S. Shackouls, 58, chairman of Burlington Resources from 1997 to 2006, and president and CEO from 1995 to 2006. President and CEO of Meridian Oil, a Burlington subsidiary, from 1994 to 1995; executive vice president and chief operating officer from 1993 to 1994. Vice chairman, Texas Heart Institute; executive board member of Sam Houston Area Council and national board member, Boy Scouts of America. Director of Peter Kiewit Sons', Inc. and The Kroger Co. Lives in Houston, Texas. (5)

Victoria J. Tschinkel, 61, director of the Florida Nature Conservancy from 2003 to 2006. Senior environmental consultant to law firm Landers & Parsons from 1987 to 2002. Former secretary of the Florida Department of Environmental Regulation. Lives in Tallahassee, Fla. (1)

Kathryn C. Turner, 61, founder, chair and CEO of Standard Technology, Inc., a management and technology solutions firm with a focus in the health care sector, since 1985. Also a director of Carpenter Technology Corporation and Schering-Plough Corporation. Lives in Bethesda, Md. (3, 4)

William E. Wade, Jr., 66, former president of ARCO (Atlantic Richfield Company), and executive vice president, worldwide exploration and production, from 1993 to 1998. Also served as president of ARCO Oil & Gas Company and ARCO Alaska. Served on the boards of ARCO, Burlington Resources, Lyondell Chemical Company and Vastar Resources. Lives in Santa Rosa Beach, Fla. (2, 3)

(1) Member of Audit and Finance Committee
(2) Member of Executive Committee
(3) Member of Compensation Committee
(4) Member of Directors' Affairs Committee
(5) Member of Public Policy Committee

Company Officers*

James J. Mulva, Chairman and Chief Executive Officer
John A. Carrig, President and Chief Operating Officer
James L. Gallogly, Executive Vice President, Exploration and Production
Gene L. Batchelder, Senior Vice President, Services, and Chief Information Officer
Stephen R. Brand, Senior Vice President, Technology
Red Cavaney, Senior Vice President, Government and Public Affairs
W.C.W. Chiang, Senior Vice President, Refining, Marketing and Transportation
Sigmund L. Cornelius, Senior Vice President, Finance, and Chief Financial Officer
Gregory J. Goff, Senior Vice President, Commercial
Janet Langford Kelly, Senior Vice President, Legal, General Counsel and Corporate Secretary
Ryan M. Lance, President, Exploration and Production – Europe, Asia, Africa and the Middle East
Luc J. Messier, Senior Vice President, Project Development
Jeff W. Sheets, Senior Vice President, Planning and Strategy
Carin S. Knickel, Vice President, Human Resources
Robert A. Ridge, Vice President, Health, Safety and Environment

Other Corporate Officers

Rand C. Berney, Vice President and Controller
Glenda M. Schwarz, General Auditor and Chief Ethics Officer
Frances M. Vallejo, Vice President and Treasurer
Ben J. Clayton, General Tax Officer
Keith A. Kliewer, Tax Administration Officer

Operational and Functional Organizations

Exploration and Production

Larry E. Archibald, Vice President, Exploration
James L. Bowles, President, Alaska
William L. Bullock, President, Middle East and North Africa
Robert G. Flesher, Vice President, Drilling and Production
Donald G. Hrap, President, U.S. Lower 48
Darren C. Jones, President, Global Gas, Strategic Planning and Business Development
Kevin O. Meyers, President, Canada
Don E. Wallette, President, Russia and Caspian Region
Paul C. Warwick, President, Europe and West Africa

Refining and Marketing

Deborah G. Adams, President, Transportation
Rex W. Bennett, President, Strategy, Integration and Specialty Businesses
Robert A. Herman, President, Europe Refining, Marketing and Transportation
C.C. Reasor, President, U.S. Marketing
Larry M. Ziemba, President, U.S. Refining

Commercial

C.W. Conway, President, Americas Supply and Trading
Todd W. Fredin, President, Europe, Africa and Middle East Trading
Glenn E. Simpson, President, Asia Supply and Trading
John W. Wright, President, Gas and Power

**As of March 1, 2009*

Glossary

Appraisal Drilling: Drilling carried out following discovery to determine a new field's physical extent, amount of reserves and likely production rate.

Aromatics: Hydrocarbons with at least one benzene ring in their structure (i.e., benzene, toluene and xylenes).

Barrels of Oil Equivalent (BOE): A term that quantifies oil and natural gas volumes using the same measurement. Natural gas is converted on the basis of energy content – 6,000 cubic feet of gas equals one barrel of oil.

Coke: A solid carbon product produced by thermal cracking.

Coker: A refinery unit that processes heavy residual material into solid carbon (coke) and lighter hydrocarbons through thermal cracking. Lighter materials are used as feedstocks to other refinery units for conversion into higher-value transportation fuels.

Condensate: Light liquid hydrocarbons. Condensates are produced with natural gas and separated by absorption, refrigeration and other processes.

Cost-Advantaged Crude: Lower-quality crude oil – typically dense, high in sulfur or highly acidic – that is price advantaged due to the limited amount of complex refining capacity available to run it.

Cyclohexane: The cyclic form of hexane used as a raw material to manufacture nylon.

Deepwater: Water depth of at least 1,000 feet.

Distillates: The middle range of petroleum liquids – diesel fuel, heating oil and kerosene – produced during crude oil processing.

Ethylene: Basic chemical used to manufacture plastics (such as polyethylene), antifreeze and synthetic fibers.

Exploitation: Focused, integrated effort to extend the economic life, production and reserves of an existing field.

Feedstock: Crude oil, natural gas liquids, natural gas or other materials used as raw ingredients for making gasoline, other refined products or chemicals.

Floating Production, Storage and Offloading (FPSO) Vessel: A floating facility for production, storage and offloading of oil. Oil and associated gas from a subsea reservoir are separated on deck, and the oil is stored in tanks in the hull for later transfer to other vessels. The gas is exported by pipeline or reinjected into the reservoir.

Fluid Catalytic Cracking (FCC) Unit: A refinery unit that cracks large hydrocarbon molecules into lighter, more valuable products, such as gasoline, propane, butane and pentane.

Improved Recovery: Technology for increasing or prolonging oil and gas field productivity.

Liquefied Natural Gas (LNG): Gas, mainly methane, that has been liquefied in a refrigeration and pressure process to facilitate storage or transportation.

Liquids: An aggregate of crude oil and natural gas liquids; also known as hydrocarbon liquids.

Margins: Difference between sales prices and feedstock costs, or between sales prices and feedstock and manufacturing costs.

Natural Gas Liquids (NGL): Mixed stream of ethane, propane, butanes and pentanes that is split into individual components for use as feedstocks for refineries and chemical plants.

Olefins: Basic chemicals (ethylene, propylene) made from oil or natural gas liquids; commonly used to manufacture plastics and gasoline.

Organic Reserve Replacement: A ratio, the numerator of which is net proved reserve additions, excluding reserves purchased and sold, and the denominator of which is net production. Designed to highlight reserves added through a company's internal exploration and development efforts.

Paraxylene: An aromatic compound used to make polyester fibers and plastic soft drink bottles.

Polyethylene: Plastic made from ethylene used in manufacturing products including trash bags, milk jugs, bottles and pipe.

Polypropylene: Basic plastic derived from propylene used in fibers, films and automotive parts.

Reservoir: A porous, permeable sedimentary rock formation containing oil and/or natural gas, enclosed or surrounded by less permeable or impervious rock.

Return on Capital Employed (ROCE): A ratio of income from continuing operations, adjusted for after-tax interest expense and minority interest, to the yearly average of total debt, minority interest and stockholders' equity.

Styrene: A liquid hydrocarbon used in making plastics by polymerization or copolymerization.

Syncrude: Synthetic crude oil derived by upgrading bitumen extracted from oil sands.

Throughput: Average amount of raw material processed in a given period.

Total Recordable Rate: A metric for evaluating safety performance calculated by multiplying total recordable cases by 200,000 and then dividing by work hours.

Vacuum Unit: A more sophisticated crude unit operating under a vacuum, which further fractionates gas oil and heavy residual material.

Wildcat Drilling: Exploratory drilling performed in an unproven area, far from producing wells.

Reconciliation of Adjusted Earnings to Net Income (Loss)

Millions of dollars, except per share amounts

Consolidated	2008	2007
Net income (loss)	**$(16,998)**	**11,891**
Less:		
Goodwill impairment	25,443	—
LUKOIL investment impairment	7,410	—
Impairment – expropriated assets	—	4,512
Impairments – other	1,292	161
Net gain on asset sales	(814)	(1,047)
Tax rate changes	—	(365)
Severance accruals	99	—
Adjusted earnings	**$ 16,432**	**15,152**
Income (loss) per share of common stock	**$ (11.16)**	**7.22**
Adjusted earnings per share of common stock*	**$ 10.66**	**9.21**
** Based on adjusted diluted shares of (in millions):*	*1,540.8*	—
E&P		
Net income (loss)	**$(13,479)**	**4,615**
Less:		
Goodwill impairment	25,443	—
Impairment – expropriated assets	—	4,512
Impairments – other	627	273
Net gain on asset sales	(590)	(708)
Tax rate changes	—	(209)
Severance accruals	71	—
Adjusted earnings	**$ 12,072**	**8,483**
R&M		
Net income	**$ 2,322**	**5,923**
Less:		
Impairments	550	(112)
Net gain on asset sales	(224)	(339)
Tax rate changes	—	(141)
Severance accruals	24	—
Adjusted earnings	**$ 2,672**	**5,331**
LUKOIL Investment		
Net income (loss)	**$ (5,488)**	**1,818**
Less: Impairment	7,410	—
Adjusted earnings	**$ 1,922**	**1,818**

Stockholder Information

Annual Meeting

ConocoPhillips' annual meeting of stockholders will be held:

Wednesday, May 13, 2009
Omni Houston Hotel Westside
13210 Katy Freeway, Houston, Texas

Notice of the meeting and proxy materials are being sent to all stockholders.

Direct Stock Purchase and Dividend Reinvestment Plan

ConocoPhillips' Investor Services Program is a direct stock purchase and dividend reinvestment plan that offers stockholders a convenient way to buy additional shares and reinvest their common stock dividends. Purchases of company stock through direct cash payment are commission-free. For details contact:

BNY Mellon Shareowner Services
P.O. Box 358035
Pittsburgh, PA 15252-8035
Toll-free number: (800) 356-0066

Registered stockholders can access important investor communications online and sign up to receive future shareholder materials electronically by going to *www.bnymellon.com/shareowner/isd* and following the enrollment instructions.

Information Requests

For information about dividends and certificates, or to request a change of address, stockholders may contact:

BNY Mellon Shareowner Services
P.O. Box 358015
Pittsburgh, PA 15252-8015
Toll-free number: (800) 356-0066
Outside the U.S.: (201) 680-6578
TDD: (800) 231-5469
Outside the U.S.: (201) 680-6610
www.bnymellon.com/shareowner

Personnel in the following offices also can answer investors' questions about the company:

Institutional Investors:

ConocoPhillips Investor Relations
375 Park Avenue, Suite 3702
New York, NY 10152
(212) 207-1996
investor.relations@conocophillips.com

Individual Investors:

ConocoPhillips Shareholder Relations
600 N. Dairy Ashford, ML3074
Houston, TX 77079
(281) 293-6800
shareholder.relations@conocophillips.com

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FSC
10%

Annual Certifications

ConocoPhillips has filed the annual certifications required by Rule 13a-14(a)/15d-14(a) of the Securities Exchange Act of 1934 as exhibits 31.1 and 31.2 to ConocoPhillips' Annual Report on Form 10-K, as filed with the U.S. Securities and Exchange Commission. Additionally, in 2008, James J. Mulva, chairman and chief executive officer, submitted an annual certification to the New York Stock Exchange (NYSE) stating that he was not aware of any violation of the NYSE corporate governance listing standards by the company. Mr. Mulva will submit his 2009 annual certification to the NYSE no later than 30 days after the date of ConocoPhillips' annual meeting of stockholders.

Internet Web Site: *www.conocophillips.com*

The site includes the Investor Information Center, which features news releases and presentations to securities analysts; copies of ConocoPhillips' Annual Report and Proxy Statement; reports to the U.S. Securities and Exchange Commission; and data on ConocoPhillips' health, safety and environmental performance. Other Web sites with information on topics in this annual report include:

www.lukoil.com
www.cpchem.com
www.dcpmidstream.com
p66conoco76.conocophillips.com

Annual Reports and Form 10-K

Copies of the Annual Report or Form 10-K, as filed with the U.S. Securities and Exchange Commission, are available free by making a request on the company's Web site, calling (918) 661-3700 or writing:

ConocoPhillips – 2008 Form 10-K
B-41 Adams Building
411 South Keeler Ave.
Bartlesville, OK 74004

Additional copies of this annual report may be obtained by calling (918) 661-3700, or writing:

ConocoPhillips – 2008 Annual Report
B-41 Adams Building
411 South Keeler Ave.
Bartlesville, OK 74004

Principal Offices

600 N. Dairy Ashford
Houston, TX 77079

1013 Centre Road
Wilmington, DE 19805-1297

Stock Transfer Agent and Registrar

BNY Mellon Shareowner Services
480 Washington Blvd.
Jersey City, NJ 07310-1900
www.bnymellon.com/shareowner

Compliance and Ethics

For guidance, or to express concerns or ask questions about compliance and ethics issues, call ConocoPhillips' Ethics Helpline toll-free: (877) 327-2272, available 24 hours a day, seven days a week. The ethics office also may be contacted via e-mail at *ethics@conocophillips.com* or by writing:

Attn: Corporate Ethics Office
ConocoPhillips
600 N. Dairy Ashford, MA2142
Houston, TX 77079

www.conocophillips.com