ConocoPhillips

2007 Annual Report

Delivering Energy.
Building Value.

Who We Are

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 in the United States. Worldwide, of non-government-controlled companies, ConocoPhillips is the sixth-largest proved reserves holder and the fifth-largest refiner.

The company is known worldwide for its technological expertise in exploration and production, reservoir management and exploitation, 3-D seismic technology and high-grade petroleum coke upgrading.

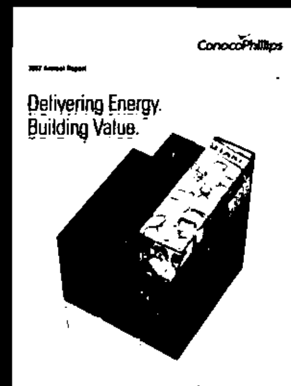
Headquartered in Houston, Texas, ConocoPhillips operates in nearly 40 countries. The company has 32,600 employees worldwide and assets of $178 billion. ConocoPhillips stock is listed on the New York Stock Exchange under the symbol "COP."

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



ConocoPhillips is engaged in delivering energy to a world that is increasingly dependent on access to abundant, reliable supplies of energy in many forms. We are dedicated to delivering this energy safely and in an environmentally responsible manner.

Throughout most of our history, we focused on producing readily available conventional oil and natural gas. As access to these supplies declined, we undertook a transition to unconventional sources — heavy oil, "tight" natural gas and coalbed methane — which now represent much of our resource base.

Today we are engaged in a further long-term transition as we develop new methods to provide these fuels in cleaner-burning forms while beginning the journey toward renewable fuels and alternative energy sources. This transition, which will require decades to accomplish, is part of a strategy through which ConocoPhillips intends to continue delivering energy responsibly to the world well into the future.

ConocoPhillips is committed to building the intrinsic value of our company by capitalizing on the opportunities offered by our substantial asset portfolio — a portfolio assembled through a combination of organic growth and acquisitions. These opportunities range from promising exploratory prospects to ongoing producing field development programs, refinery upgrades, expansions of our downstream businesses and entry into emerging forms of alternative energy.

Further, we are committed to building the value realized by ConocoPhillips shareholders in return for their investment in our shares. During 2007 our shareholders realized a 25.4 percent return on their investment, the fifth consecutive year of returns exceeding 25 percent. We increased the quarterly dividend by 14 percent and made $7 billion in share repurchases. In early 2008, we announced a 15 percent increase in the quarterly dividend, and we have an additional $10 billion in share repurchases authorized for 2008. In the future, we plan to allocate a significant portion of our discretionary cash for return to shareholders through share repurchases and dividends.

Financial Highlights

	Millions of Dollars Except as Indicated		
	2007	2006	% Change
Financial			
Total revenues and other income	**$194,495**	188,523	3 %
Net income	**$ 11,891**	15,550	(24)
Net income per share of common stock — diluted	**$ 7.22**	9.66	(25)
Net cash provided by operating activities	**$ 24,550**	21,516	14
Capital expenditures and investments	**$ 11,791**	15,596	(24)
Total assets	**$177,757**	164,781	8
Total debt	**$ 21,687**	27,134	(20)
Minority interests	**$ 1,173**	1,202	(2)
Common stockholders' equity	**$ 88,983**	82,646	8
Percent of total debt to capital*	**19%**	24	(21)
Common stockholders' equity per share (book value)	**$ 56.63**	50.21	13
Cash dividends per common share	**$ 1.64**	1.44	14
Closing stock price per common share	**$ 88.30**	71.95	23
Common shares outstanding at year end (in thousands)	**1,571,430**	1,646,082	(5)
Average common shares outstanding (in thousands)			
Basic	**1,623,994**	1,585,982	2
Diluted	**1,645,919**	1,609,530	2
Employees at year end (in thousands)	**32.6**	38.4	(15)

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

	2007	2006	% Change
Operating*			
U.S. crude oil production (MBD)	**363**	367	(1)%
Worldwide crude oil production (MBD)	**854**	972	(12)
U.S. natural gas production (MMCFD)	**2,292**	2,173	5
Worldwide natural gas production (MMCFD)	**5,087**	4,970	2
Worldwide natural gas liquids production (MBD)	**155**	136	14
Worldwide Syncrude production (MBD)	**23**	21	10
LUKOIL Investment net production (MBOED)**	**444**	401	11
Worldwide production (MBOED)***	**2,324**	2,358	(1)
Natural gas liquids extracted — Midstream (MBD)	**211**	209	1
Refinery crude oil throughput (MBD)	**2,560**	2,616	(2)
Refinery utilization rate	**94%**	92	2
U.S. automotive gasoline sales (MBD)	**1,244**	1,336	(7)
U.S. distillates sales (MBD)	**872**	850	3
Worldwide petroleum products sales (MBD)	**3,245**	3,476	(7)
LUKOIL Investment refinery crude oil throughput (MBD)**	**214**	179	20

*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.

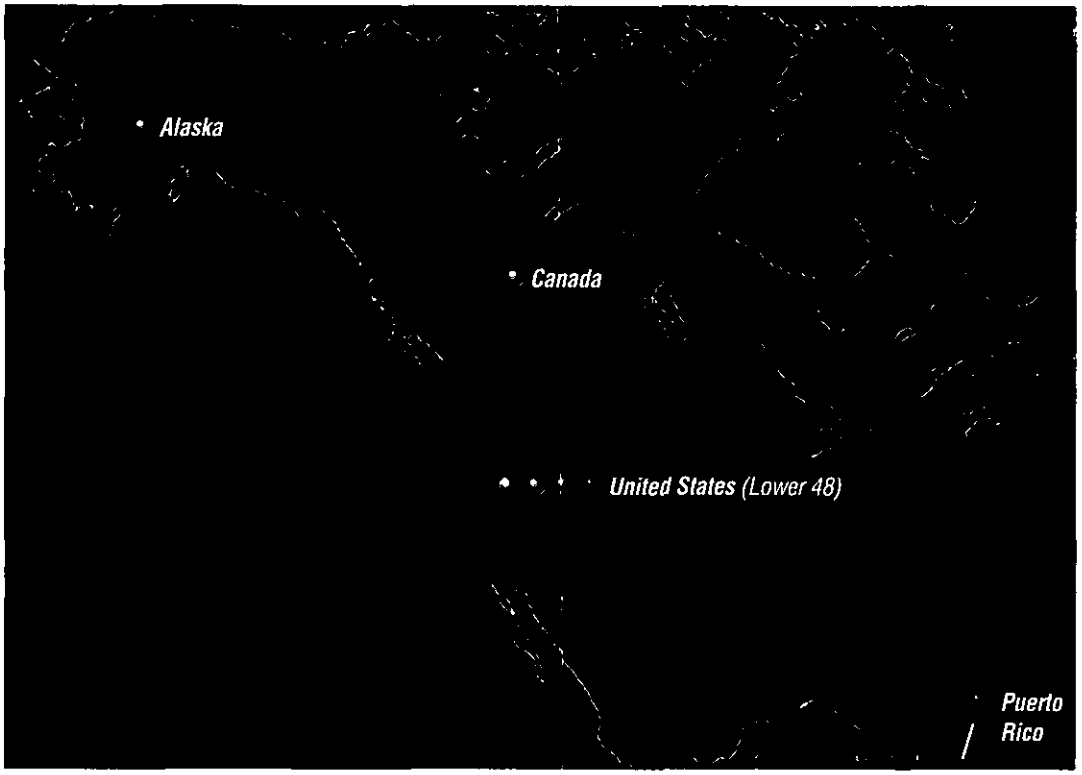
Certain disclosures in this Annual Report may be considered "forward-looking" statements. These are made pursuant to "safe harbor" provisions of the Private Securities Litigation Reform Act of 1995. The "Cautionary Statement" in Management's Discussion and Analysis on page 53 should be read in conjunction with such statements.

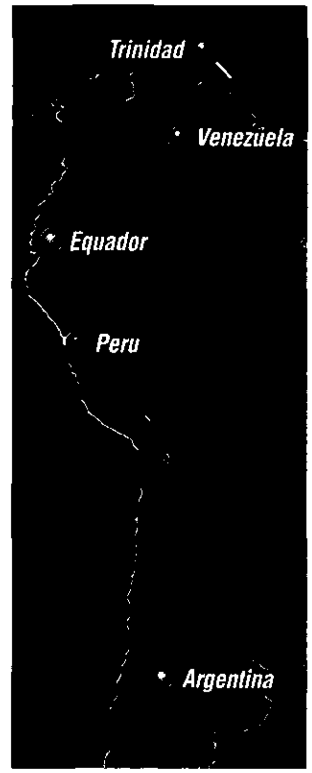
Cautionary Note to U.S. Investors — The United States Securities and Exchange Commission (SEC) permits oil and gas companies, in their filings with the SEC, to disclose only proved reserves that a company has demonstrated by actual production or conclusive formation tests to be economically and legally producible under existing economic and operating conditions. The company uses certain terms in this Annual Report, such as "resources," "recoverable resources," "resource base," and "recoverable bitumen," that the SEC's guidelines strictly prohibit us from including in filings with the SEC. U.S. investors are urged to consider closely the disclosures in the company's 2007 Form 10-K, File No. 001-32395, available from the company at 600 N. Dairy Ashford, Houston, TX 77079, and the company's Web site at *www.conocophillips.com/investor/sec.htm*. The 2007 Form 10-K also can be obtained from the SEC by calling 1-800-SEC-0330.

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

Worldwide Operations

ConocoPhillips operates responsibly in nearly 40 countries throughout the world, providing reliable and sustainable energy supply that powers modern life.





Exploration and Production (E&P)

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

Operations: At year-end 2007, E&P held a combined 68.5 million net developed and undeveloped acres in 23 countries and produced hydrocarbons in 16, with proved reserves in three additional countries. Crude oil production in 2007 averaged 854,000 barrels per day (BD), natural gas production averaged 5.09 billion cubic feet per day (BCFD), and NGL production averaged 155,000 BD.

Refining and Marketing (R&M)

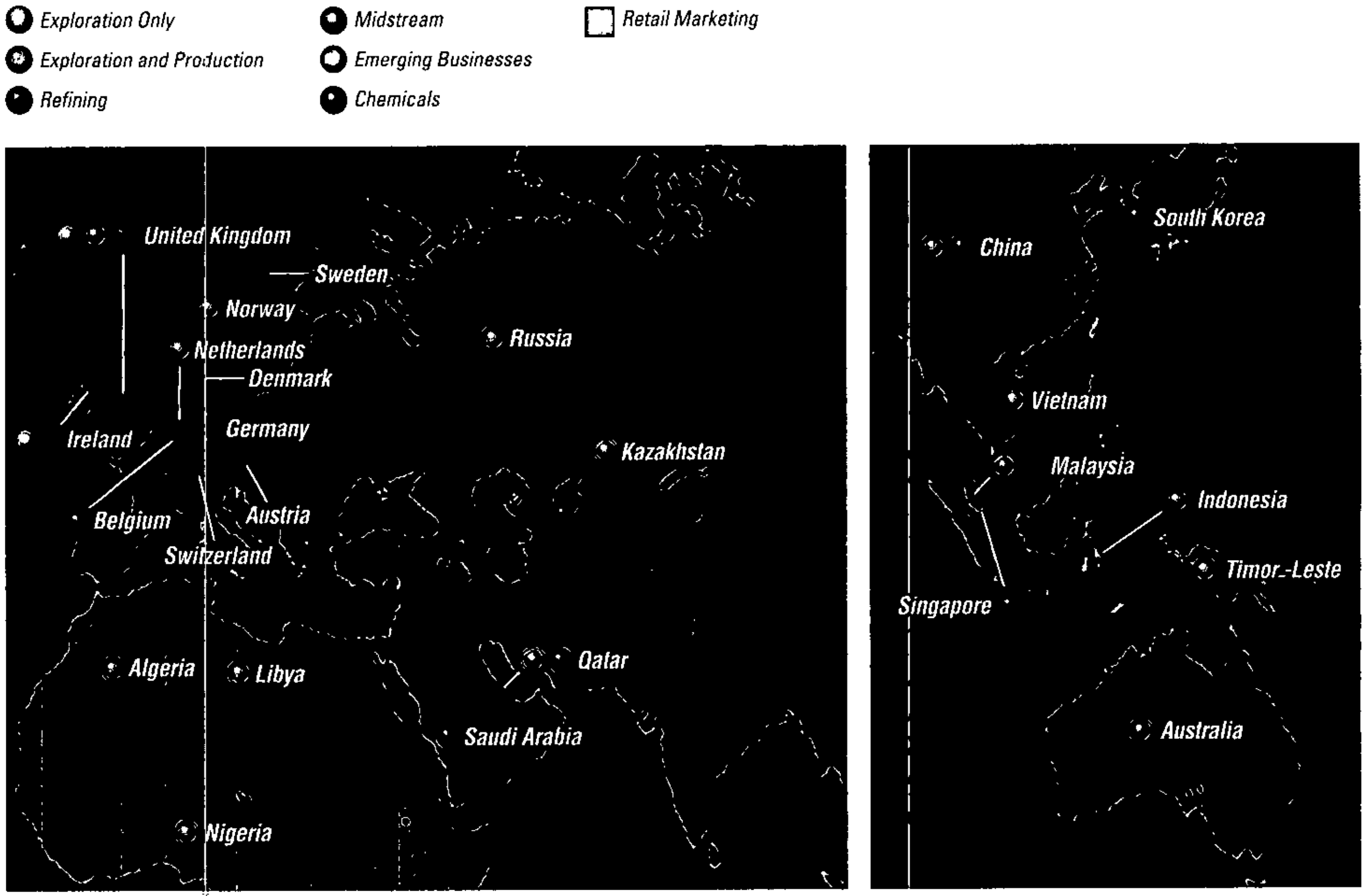
Profile: R&M refines crude oil and other feedstocks into petroleum products and markets and transports them. Based on crude oil capacity, ConocoPhillips is the world's fifth-largest refiner and the second-largest U.S. refiner.

Operations: R&M has operations in the United States, Europe and the Asia Pacific region. *Refining* – At year-end 2007, R&M owned or had interests in 12 U.S. refineries, with an aggregate crude oil processing capacity of 2,037,000 BD. It also owned or had interests in five refineries outside the United States, with an aggregate crude oil processing capacity of 669,000 net BD. *Marketing* – At year-end 2007, the group sold gasoline, distillates and aviation fuel through approximately 10,500 outlets in the United States and Europe. In the United States, products were marketed primarily under the Phillips 66®, Conoco® and 76® brands and in Europe primarily under the JET® brand. The group 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 3.2 million BD in 2007. *Transportation* – At year-end 2007, the company 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 20 percent ownership in LUKOIL, an international, integrated oil and natural gas company headquartered in Russia.

Operations: At year-end 2007, LUKOIL had exploration, production, refining and marketing operations in about 30 countries. During 2007, ConocoPhillips' estimated share of LUKOIL's production was 444,000 barrels of oil equivalent per day and refining crude oil throughput was 214,000 BD.



Midstream

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

Operations: At year-end 2007, DCP Midstream had approximately 58,000 miles of pipelines and owned or operated 53 extraction plants and 10 fractionation plants. Its raw natural gas throughput averaged 5.9 BCFD, and NGL extraction averaged 363,000 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 2007, CPChem had 11 U.S. facilities; nine polyethylene pipe, conduit and pipe fittings plants; and a petrochemical complex in Puerto Rico. Major international production facilities were in Belgium, China, Saudi Arabia, Singapore, South Korea and Qatar.

Emerging Businesses

Profile: Emerging Businesses develops new businesses and technology complementary to traditional operations. These include power generation, which develops integrated projects to support E&P and R&M strategies and business objectives; carbons-to-liquids, a process that converts carbon into a wide range of transportable products; technology solutions, which develops upstream and downstream technologies and services; and alternative energy and programs, which involve heavy oils, biofuels and alternative energy sources designed to provide future growth options.

Operations: In 2007, the company formed an alliance to collaborate on developing renewable transportation fuels from biomass such as crops, wood or switchgrass. It also entered into an agreement to explore developing a commercial-scale coal-to-substitute-natural-gas (SNG) facility using proprietary ConocoPhillips E-Gas™ technology. In late 2007, the company also began processing tallow at its Borger, Texas, refinery to make renewable diesel fuel.

Letter to Shareholders

Delivering Energy, Building Value

James J. Mulva
Chairman and
Chief Executive Officer

To Our Shareholders:

During 2007 ConocoPhillips operated reliably and profitably, overcoming numerous challenges in the increasingly competitive international oil and natural gas industry. Our strategic direction remained consistent. We continued to enhance our portfolio through capital investments. We built additional value for shareholders by increasing our annual stock dividend rate and making significant share repurchases. We also prudently managed our balance sheet.

Safety and environmental stewardship remain core values at ConocoPhillips. Our performance improved during 2007, and we continue working toward our "Journey to Zero" goals of zero injuries, incidents and occupational illnesses. Enhancing this performance was our ongoing emphasis on operating excellence and associated efforts to improve process safety and operational reliability.

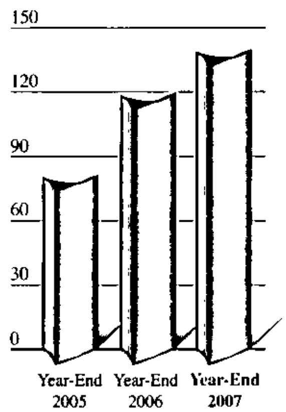
Net income during 2007 was $11.9 billion, or $7.22 per share, compared with $15.6 billion, or $9.66 per share, in 2006. The 2007 results included an after-tax impairment of $4.5 billion resulting from the expropriation of our Venezuelan oil projects. Excluding this impairment, 2007 earnings were $16.4 billion or $9.97 per share. We have filed a request for international arbitration concerning the Venezuelan expropriation, while continuing to negotiate in an effort to reach an amicable settlement on compensation. Our capital program totaled $12.9 billion.

ConocoPhillips shareholders realized a 25.4 percent return on their investment during 2007 through share price appreciation and dividends, the fifth consecutive year of returns exceeding 25 percent. We increased the quarterly dividend by 14 percent and undertook a significant share repurchase program. Our repurchases totaled 89.5 million shares for $7 billion during 2007. For 2008, $10 billion in additional repurchases are authorized, and during the first quarter we declared an additional 15 percent increase in the quarterly dividend.

Total debt was reduced by $5.4 billion during 2007 to $21.7 billion, compared with $27.1 billion at year-end 2006. This reduction lowered the debt-to-capital ratio to 19 percent. We foresee no current need for further significant debt reduction.

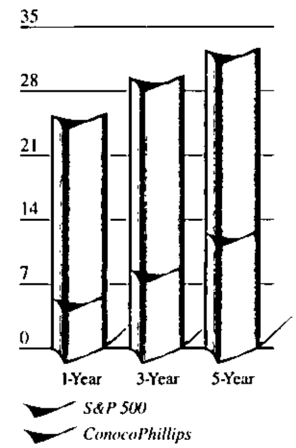
Over the long term, ConocoPhillips strives to achieve financial performance differential to that of our peers as measured on a per-barrel basis. During 2007, our Refining and Marketing (R&M)

Market Capitalization
(Billions of Dollars)



ConocoPhillips' market capitalization was $139 billion at the end of 2007, representing a 17 percent increase from 2006. The company had 1,571 million shares outstanding on Dec. 31, 2007, with a year-end closing price of $88.30.

Total Shareholder Return
(Annual Average Percent)



The company's total shareholder return for 2007 was 25.4 percent, second among its peers. ConocoPhillips' annualized return to shareholders over the three-year period was 29.4 percent and over a five-year period was 32.6 percent.

business generated income and cash per barrel well above its peer-group average. Our Exploration and Production (E&P) sector outperformed its peer group on cash per barrel but slightly underperformed on income per barrel due to the purchase accounting impact of recent acquisitions. The company's overall return on capital employed was just under the peer-group average.

Operational Milestones

Among the year's operational highlights, ConocoPhillips:

- Produced 2.3 million barrels of oil equivalent (BOE) per day, including volumes from our E&P sector and our LUKOIL investment. We achieved reserve replacement of 159 percent, excluding the impact of the Venezuelan expropriation. Total reserves were 10.6 billion BOE at year end. LUKOIL yielded 0.4 million BOE per day of our net production and $1.8 billion in income.
- Started up the Surmont heavy-oil project in Canada, the Kerisi natural gas project in Indonesia, and the Statfjord Late Life and Kelvin oil projects in the North Sea.
- Achieved a worldwide refining crude oil capacity utilization rate of 94 percent, an increase from 2006. Our U.S. utilization rate of 96 percent exceeded the industry average for the sixth consecutive year. R&M also increased its capacity to process lower-quality, cost-advantaged feedstock and to produce clean fuels.
- Successfully initiated the upstream and downstream business ventures with EnCana and began upgrading the Borger and Wood River refineries to increase their heavy-oil processing capacity.
- Refocused our exploration program to increase exposure to world-class prospects. This process began with thorough geological studies of areas offering major resource potential, followed by key lease acquisitions. We expect to increase wildcat drilling in the future. During 2007, we achieved discoveries in the North Sea, Malaysia and Nigeria. We also continued successful low-risk exploration in the United States and western Canada, primarily in highly prospective resource plays, and added 476,000 acres of new leases.
- Progressed nearly 40 major development projects toward startup. In Kazakhstan, development proceeded on the Kashagan field, and we and our co-venturers reached an agreement with the government on the project's costs and schedule and on increasing the government's ownership interest.
- Continued growing the Commercial organization, improving our ability to secure refining feedstocks at favorable cost and sell our products at attractive margins. We concurrently increased our pipeline, terminal, marine transportation and transmission capacities.
- Rationalized our portfolio, realizing $3.6 billion in proceeds primarily from the sale of non-core exploratory and producing properties and refining and marketing assets. We plan further selective divestments to facilitate ongoing portfolio renewal.
- Increased annual spending on technology to $400 million, with $250 million devoted to existing businesses and $150 million to new research and emerging businesses. We expanded our alternative energy capabilities by introducing renewable diesel

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fuel made from byproduct animal fat, formed an alliance to research production of advanced biofuels from non-food sources, undertook a study on producing synthetic natural gas from coal, and funded several university research programs.

Key Operating and Strategic Initiatives

ConocoPhillips utilizes a well-defined strategy to build shareholder value.

We pursue capital growth by capturing the opportunities inherent in our high-quality asset base, as well as newly developed opportunities that meet our operating and financial parameters. We do this with a balance that serves both energy consumers and shareholders, driven by operating and financial performance that continues to enhance our financial strength and flexibility. Cash flow in excess of immediate capital investment needs is predominantly dedicated to the direct benefit of shareholders through share repurchases and dividends. These complementary actions build the underlying value of our base businesses, with this value enhanced on a per-share basis by share repurchases and dividends.

The process begins with our attractive assets. We are a leading North American oil and natural gas producer, with a major legacy position in the North Sea and growth prospects in the Middle East, Asia Pacific, Russia and the Caspian Sea. Our R&M business stands second in U.S. crude oil refining capacity and offers opportunities to increase refining complexity and capacity to manufacture environmentally desirable clean fuels. Our other downstream businesses further leverage the energy value chain.

To exploit the opportunities available, we plan a $15.3 billion capital program for 2008, with $12 billion allocated to E&P, $2.8 billion to R&M, and $500 million to Emerging Businesses and Corporate. Key E&P goals also include averaging at least 100 percent annual reserve replacement and 2 percent annual production growth. In response to current industry cost inflation, our priority will be creating value.

The Challenging Industry Environment

The global energy market appears poised for long-term strength, driven by growing world population and increased energy demand in developing countries. We believe ConocoPhillips is favorably positioned to operate in this environment and to cope with the market's vulnerability to occasional downturns. Although the energy industry faces challenging operational obstacles, we believe that we are prepared to meet them.

Perhaps foremost among these challenges is society's need to achieve energy supply security and its desire to address the climate impact of greenhouse gas emissions.

ConocoPhillips believes that energy supply security would improve significantly if national governments opened access to restricted areas known to offer energy development potential and encouraged the more efficient use of energy.

However, we also believe that climate-change concerns must be addressed, and that neither issue can be solved separately. Otherwise, public concerns over potential energy shortages would defeat efforts to reduce greenhouse gas emissions, while concerns over climate change would defeat energy development initiatives. These global issues must be addressed together through well-integrated government policies.

Recent energy legislation in the United States focused exclusively on promoting renewable and alternative energy. The legislation ignored the vast oil and natural gas potential located on public lands that are off limits to drilling and the vital role these energy sources must play in the future.

ConocoPhillips therefore calls for enactment of a comprehensive U.S. energy policy that facilitates production of all energy sources, enhances energy efficiency, and initiates action on climate change. We believe the public would welcome such a policy.

We further call on the energy industry to engage in the debate on climate-change solutions. During 2007, ConocoPhillips became the only major U.S.-based oil company to join the U.S. Climate Action Partnership, which supports development of a mandatory national framework to reduce greenhouse gas emissions. In anticipation of possible future regulations, we are preparing carbon baselines and incorporating potential carbon costs into our capital projects. We also

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joined the Duke University Climate Change Partnership, which is striving to develop workable public policies.

ConocoPhillips is responding to other vital issues, such as the growing tendency of energy-exporting countries to restrict access to their resources. Some allow only their national oil companies to operate within their borders. Others impose impractical fiscal terms or, on occasion, even violate contracts and expropriate properties. These actions tend to tighten energy supplies, despite the fact that the world still possesses substantial undeveloped potential.

ConocoPhillips is well-suited to withstand this resource nationalism because a significant proportion of our assets are located in the United States, Canada, European nations and other Organization of Economic Cooperation and Development (OECD) member countries.

Additionally, in order to overcome industry-wide shortages of technical personnel, we broadened our college and experienced recruiting programs. To meet the growing need for innovation, we significantly increased research and development expenditures. And to resist cost inflation, we implemented more comprehensive planning and procurement strategies for our development projects.

Corporate Citizenship

While ConocoPhillips believes that our responsibility to society begins with providing reliable and sustainable energy, we also are committed to improving the well-being of the communities in which we operate.

One of the many ways we practiced corporate citizenship during 2007 was the contribution of approximately $60 million in donations to worthy educational, youth, health, social service, civic, art, environmental and safety initiatives, as well as charities. Our employees also contributed thousands of hours of their personal time to these causes.

To enhance dialogue with the public, we continued our Conversation on Energy program, advocating wider diversification of energy supply sources, more efficient energy use, greater technological innovation and environmental responsibility. By year-end 2007, members of management had visited 35 U.S. cities to meet with the public, political leaders, educators and the media. We also created accompanying television and print advertising. Our plans are to continue this dialogue in 2008.

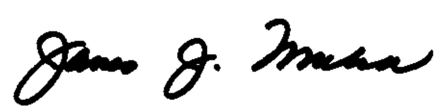
ConocoPhillips is taking action on a number of environmental concerns. For example, to enhance the worldwide availability of fresh water, we are establishing a water sustainability center in Qatar. It will research the safe reuse in farm and industrial applications of byproduct water from oil production and refining.

The ConocoPhillips of Tomorrow

Our results for 2007 represent substantial progress in increasing the ability of ConocoPhillips to deliver sustainable supplies of energy. For now, we must focus primarily on developing oil and natural gas. These essential energy sources power today's economy and are needed to serve as bridging fuels until the energy sources of tomorrow are developed in sufficient scale.

Concurrently, we are working to bring unconventional fossil fuels to market in cleaner forms while developing biofuels and other renewable energy sources.

We are determined to continue this progress, while in the near term meeting our goals of delivering energy reliably and profitably, generating growth, and building shareholder value.



James J. Mulva
Chairman and Chief Executive Officer
March 1, 2008

Financial Review

Consistent Growth and Capital Discipline

ConocoPhillips exercises a consistent, proven investment strategy that balances allocations of the company's cash flow in order to grow the asset base, return capital to shareholders through dividends and share repurchases, and manage debt. Allocations vary in response to changing industry conditions and the emergence of new opportunities.

In recent years ConocoPhillips successfully expanded its portfolio through key acquisitions and investments. Meanwhile, the company's consistent operating performance and favorable market conditions made possible significant reductions in debt.

"Our opportunity portfolio and financial strength enable ConocoPhillips to focus on increasing our shareholder distributions," says John Carrig, executive vice president, Finance, and chief financial officer.

2007 Financial Results

During 2007 ConocoPhillips earned net income of $11.9 billion, or $7.22 per share, compared with 2006 net income of $15.6 billion, or $9.66 per share. Excluding the impact of a $4.5 billion non-cash impairment charge recorded in connection with the Venezuelan expropriation, 2007 earnings were $16.4 billion. Cash flow from operating activities reached $24.6 billion, a 14 percent increase over 2006. The company's performance compared favorably with that of its industry peers on many key financial and operational metrics.

Dividends and Share Repurchases

Shareholders received a 14 percent increase in quarterly dividends paid on ConocoPhillips stock during 2007, the sixth consecutive annual increase since the company's formation in 2002. A further increase of 15 percent was declared in the first quarter of 2008.

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

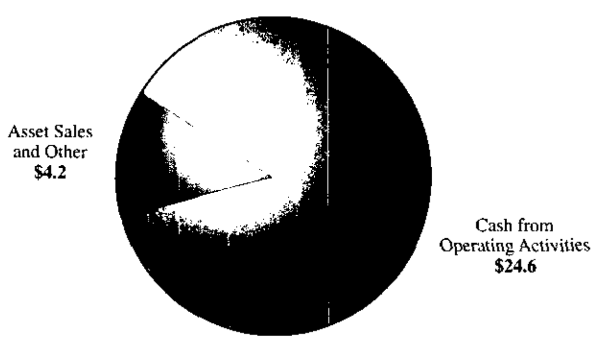
The company's commitment to returning additional cash flow to shareholders was evident in its share repurchase programs. An initial $1 billion program announced in January was expanded to $4 billion in February. At mid year, ConocoPhillips announced a $15 billion program for the balance of 2007 and 2008, including $2 billion remaining under the February program. Repurchases totaled $7 billion in 2007, with a remaining $10 billion authorized for repurchases in 2008.

"These repurchases supplement and expand the underlying growth in our base businesses on a per-share basis," Carrig says. "This in turn improves earnings per share and generates value for our shareholders."

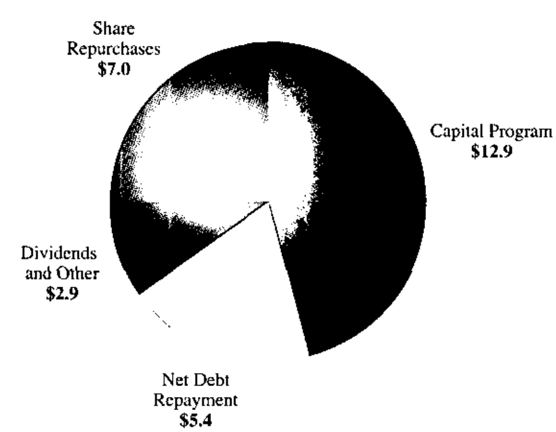
Debt Reduction

Total debt was reduced by $5.4 billion during 2007, following a $5.1 billion reduction in 2006 during the nine months following the Burlington Resources acquisition. These reductions and the company's

Sources of Cash in 2007
(Billions of Dollars)

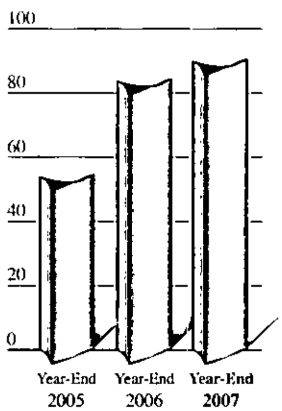


Uses of Cash in 2007
(Billions of Dollars)



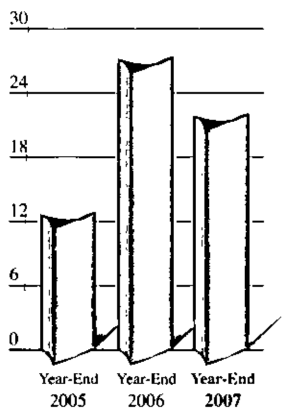
Debt Ratio: In 2007, the company's total equity grew to $90.2 billion and debt decreased to $21.7 billion. The debt-to-capital ratio declined to 19 percent at the end of 2007.

Equity*
(Billions of Dollars)

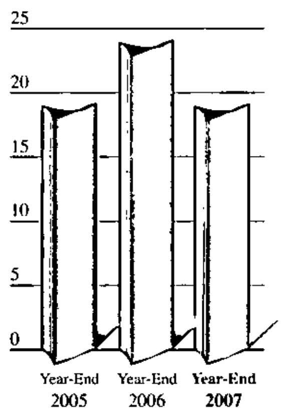


*Includes minority interest.

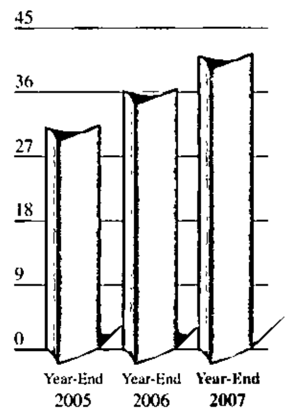
Debt
(Billions of Dollars)



Debt to Capital
(Percent)



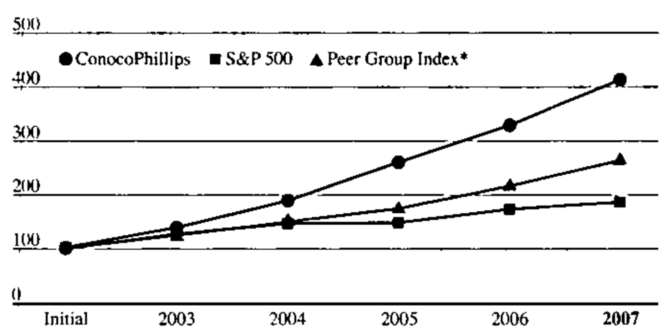
Quarterly Dividend Rate
(Cents per Share)



strong financial results strengthened the balance sheet, allowing the establishment of a 20 percent to 25 percent target range for its debt-to-capital ratio.

"That ratio stood at only 19 percent at year-end 2007, so we currently foresee no need for further significant debt reductions," Carrig says. Total debt was $21.7 billion at year-end 2007, compared with $32.2 billion at the end of the first quarter of 2006. Stockholders' equity and minority interests increased to $90.2 billion at year-end 2007, from $83.8 billion the year before.

Five-Year Cumulative Total Stockholder Returns
(Dollars; Comparison Assumes $100 Was Invested on Dec. 31, 2002)



*BP; Chevron; ExxonMobil; Royal Dutch Shell; Total

Portfolio Rationalization

During 2007, ConocoPhillips realized $3.6 billion in proceeds from the sale of assets, primarily non-core exploratory and producing properties and select refining and marketing assets.

"Our optimization efforts will continue," Carrig says. "We believe there are ongoing opportunities to divest the relatively few properties that offer limited growth potential, then redeploy the proceeds and continually upgrade our portfolio."

Capital Program

The company's capital program during 2007 totaled $12.9 billion, compared with $16.4 billion in 2006. The decrease was primarily attributable to the completion of purchases of LUKOIL shares in 2006.

The 2008 capital expenditures and investments budget is $14.3 billion, including capitalized interest. Loans to affiliates and contributions to fund the EnCana venture are expected to add $1 billion, bringing the total authorized capital program to $15.3 billion.

"We are exercising disciplined operating and capital expenditure programs in recognition of the industry environment of restricted access to new resources, service-cost inflation and intense competition," Carrig says.

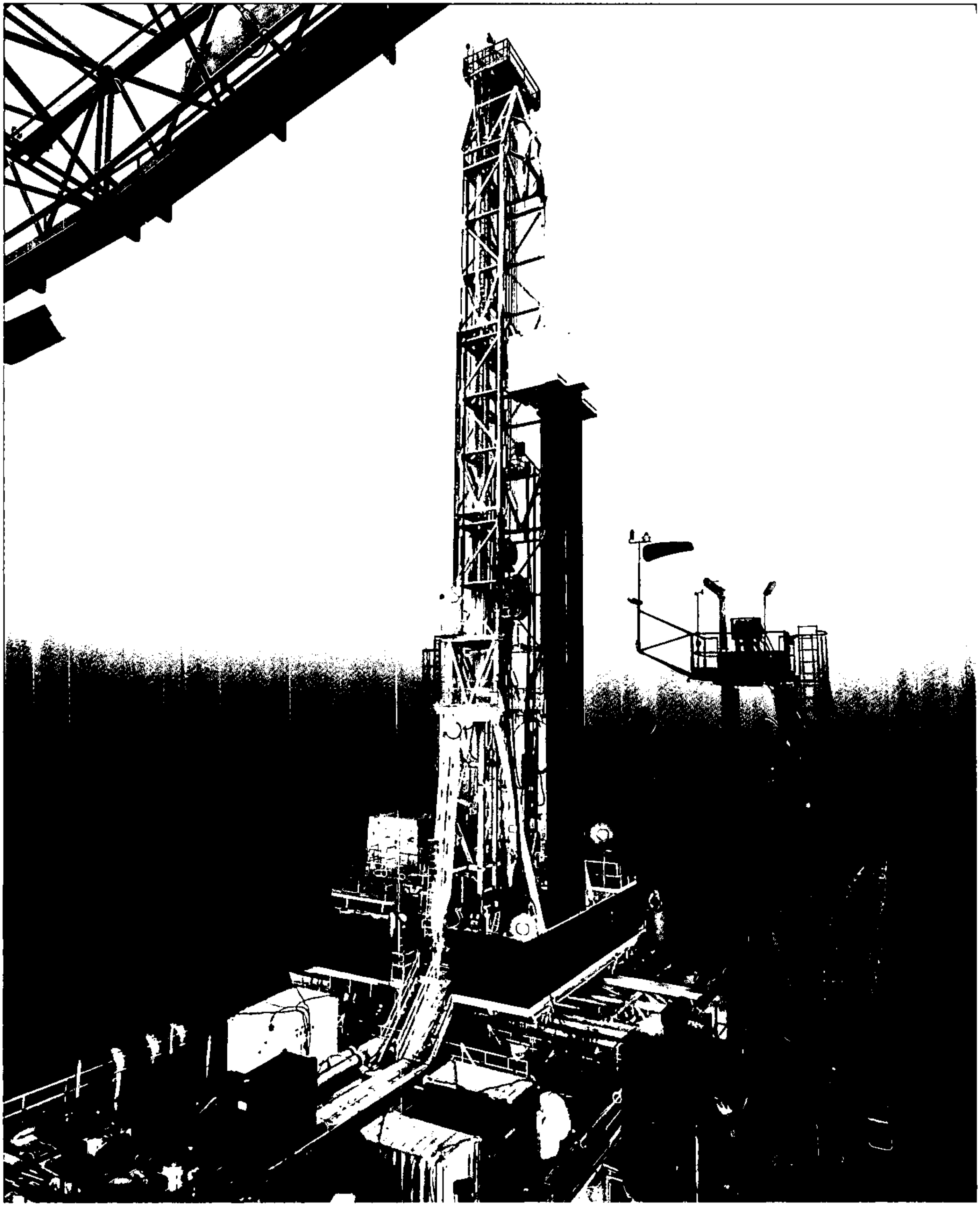
The $12 billion Exploration and Production 2008 capital program is primarily allocated for the development of producing properties in the United States, Canada, the North Sea, the Asia Pacific region, Russia and the Caspian Sea, with $1.6 billion earmarked for worldwide exploration.

Of Refining and Marketing's $2.8 billion 2008 capital program, $1.6 billion is allocated to U.S. refining and $400 million to international refining to enhance reliability, energy efficiency, maintenance and regulatory compliance; increase crude oil and conversion capability and clean-product yields; and conduct a major upgrade of the Wilhelmshaven refinery.

Additionally, $800 million is allocated for North American transportation and marketing, including the Keystone crude oil pipeline.

Other planned capital expenditures include $500 million for Emerging Businesses and Corporate. Outside the company's capital program, ConocoPhillips also plans research and technology expenditures of $250 million to support its primary businesses and $150 million on unconventional oil and natural gas and alternative and renewable energy sources.

Operating Review



Exploration and Production

Delivering Energy Through Worldwide Resource Development

2007 Major Accomplishments

- Pursued growth through 35 major development projects, two-thirds of which are expected to start up in the next five years.
- Responded to the challenging industry operating environment.
- Built a legacy position in the prolific Canadian oil sands trend.

Exploration and Production Financial and Operating Results

	2007*	2006
Net income (MM)	**$ 4,615**	$ 9,848
Proved reserves[1] (BBOE)	**10.6**	11.2
E&P worldwide production[2] (MBOED)	**1,880**	1,957
E&P crude oil production (MBD)	**854**	972
E&P natural gas production (MMCFD)	**5,087**	4,970
E&P realized crude oil price ($/bbl)	**$ 67.11**	$ 60.37
E&P realized natural gas price ($/mcf)	**$ 6.26**	$ 6.19

*Amounts reflect the expropriation of the company's Venezuelan oil projects.

[1] Includes LUKOIL.

[2] Includes Syncrude.

John E. Lowe
Executive Vice President, Exploration and Production

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

For ConocoPhillips' Exploration and Production (E&P) business, 2007 was a year of operational progress in a number of areas despite challenges posed by the intensely competitive international oil and natural gas industry.

Highlights included the attainment of a leading ownership position in Canada's Athabasca oil sands trend, the startup of several producing projects and ongoing progress on many others, and the continued strengthening of its exploration program. These successes and the company's substantial opportunity portfolio have favorably positioned ConocoPhillips for the future.

"Our prospects and capabilities have never been greater," says John Lowe, executive vice president, E&P. "We have 35 major development projects under way, two-thirds of which we expect to start up in the next five years, and we have opportunities to further maximize production from our legacy assets."

E&P holds one of the industry's largest land positions in North America and is a leading operator in many of its key producing regions.

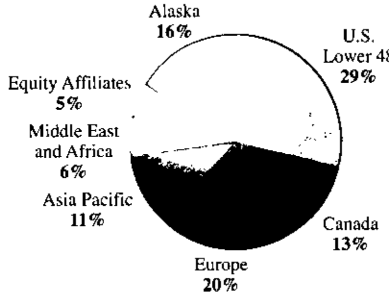
As always, E&P's most important priority is safety. Its total recordable incident rate declined by more than 20 percent in 2007, and E&P is working to further improve process safety and personal safety performances.

During the year, E&P benefited from favorable crude oil and natural gas prices, but production declined due in part to the expropriation of the company's Venezuelan oil projects. E&P delivered production (including Syncrude) of 1.88 million barrels of oil equivalent (BOE) per day, a 4 percent decrease from 2006. ConocoPhillips' 2007 reserve replacement was 159 percent, excluding the expropriation impact, or 29 percent including the expropriation impact. Total proved reserves (excluding Syncrude) at year-end 2007 were 10.6 billion BOE. E&P conducted an $11 billion capital program during 2007 and plans a $12 billion program for 2008, including a joint venture aquisition obligation and loans to affiliates.

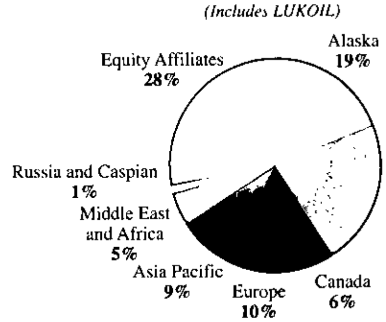
"We were disappointed by the Venezuelan expropriation, but we continue negotiations concerning appropriate compensation and are hopeful that an amicable settlement can be achieved," Lowe says. "In order to protect the interest of our shareholders, we also filed a request for arbitration with the World Bank's International Centre for the Settlement of Investment Disputes."

<< Production from this platform in Bohai Bay began in June 2007, a milestone in the six-year, multiphase development of Peng Lai, one of China's largest offshore oil fields. Ultimately, the field development will include six platforms and a floating production and storage facility.

2007 E&P Production



2007 Proved Reserves
(Includes LUKOIL)



ConocoPhillips gained access to substantial oil sands reserves in Canada through the addition of 50 percent interests in Christina Lake (pictured) and Foster Creek development projects via the EnCana venture. The two projects are estimated to hold 6.3 billion gross barrels of recoverable bitumen, adding to ConocoPhillips' substantial position in the oil sands trend.

Worldwide Operational Milestones

E&P recorded a number of exploration, development and strategic accomplishments during 2007.

The company's agreement with EnCana Corporation, finalized early in the year, created an integrated heavy-oil venture that includes a 50 percent interest in the Foster Creek and Christina Lake oil sands projects in Alberta. Through the initial acquisition and subsequent extensions and discoveries, this partnership contributed over 600 million barrels to year-end proved reserves. The projects are estimated to hold 6.3 billion gross barrels of recoverable bitumen. Current production from these projects is about 60,000 gross barrels of oil per day (BOD), with significant growth expected over the next decade. Additionally, the ConocoPhillips-operated Surmont phase I oil sands project started production in the fourth quarter.

E&P's exploration achievements included two successes in the U.K. North Sea. A natural gas discovery, Jasmine Northeast Terrace, was achieved near the 2006 Jasmine discovery; and the Clair phase II appraisal program confirmed the viability of the Clair Ridge discovery, with development planning under way. In East Texas, the Turner and Feldman natural gas discoveries, near the Savell field, enhanced the company's position in the prolific Bossier Trend.

In order to strengthen its exploration portfolio, the company added 30 deepwater tracts in the Gulf of Mexico, as well as offshore acreage in Australia, Indonesia and the North Sea. E&P also added 476,000 net acres onshore in Canada and the U.S. Lower 48 states, as well as onshore acreage in Peru.

Additionally, in the Asia Pacific region, growth continued offshore Malaysia, with the Gumusut-Kakap field development sanction and the Petai discovery. E&P also was successful in acquiring the Kebabangan Cluster production sharing contract. In Nigeria, E&P conducted successful exploration and appraisal programs onshore and offshore.

Among development milestones, first production was achieved in Indonesia's Kerisi field, Colorado's Piceance Basin, the Statfjord Late Life program in the Norwegian North Sea, and the Kelvin platform in the U.K. North Sea.

Progress occurred on a number of major, ongoing projects including the development of multiple oil-producing facilities in Bohai Bay offshore China. The first wellhead platform from the phase II development was placed onstream in 2007, and full field startup is expected in 2009. Progressing toward startup in 2008 were the North Sea Britannia satellite fields and the Yuzhno Khylchuyu field, part of the Naryanmarneftegaz joint venture with LUKOIL in northern Russia. In preparation for the 2009 startup of the Qatargas 3 natural gas liquefaction facility in Qatar, three production jackets were installed and development drilling was initiated. ConocoPhillips also acquired an interest in the Golden Pass regasification facility, which is under construction near Sabine, Texas. It will be supplied by Qatargas 3.

In Kazakhstan, development of the Kashagan field continued with the construction of artificial drilling islands, processing facilities, living quarters and pipelines. The project's co-venturers also reached a preliminary agreement with the government of Kazakhstan on the development costs and schedule and on increasing the Kazakhstan national oil company's ownership percentage in the project. As a result, ConocoPhillips' ownership interest in the project would decline from 9.26 percent to 8.40 percent.

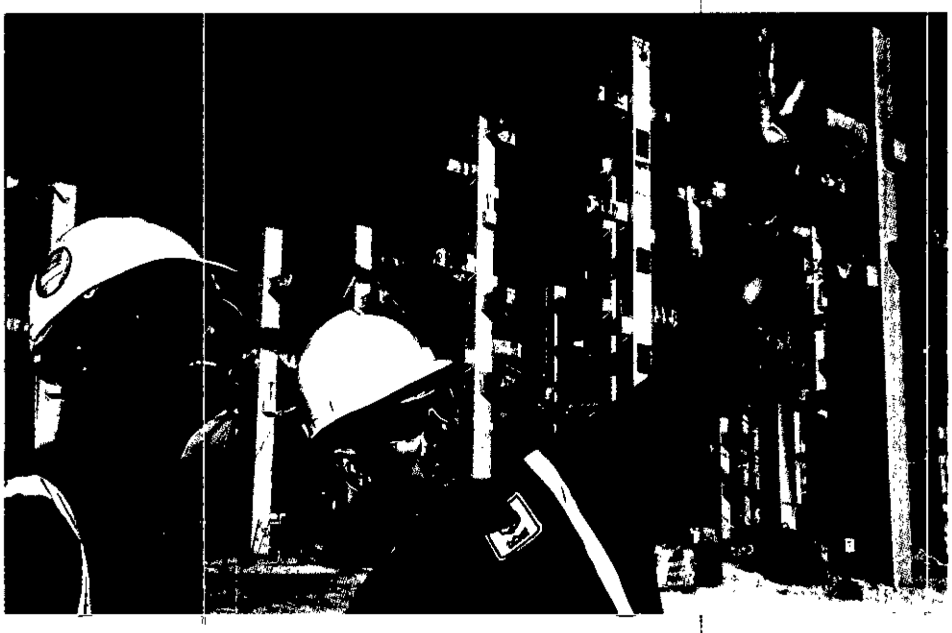
The Piceance Basin was the site of an innovative approach to reduce the impact of drilling activity. E&P built temporary living quarters for up to 400 contract workers, and it has been lauded by community leaders and neighbors for shrinking the operating footprint, reducing traffic congestion and eliminating local infrastructure needs.

Portfolio rationalization was another key 2007 achievement, as E&P sold non-core assets in seven countries for approximately $2 billion.

"These were generally mature producing properties scattered throughout our worldwide portfolio

In Qatar, workers survey the progress of the massive Qatargas 3 natural gas liquefaction plant. Throughout its planned 25-year lifespan, the facility is expected to yield 1.4 billion cubic feet per day of LNG for export to world markets, including the United States.

As one of North America's largest natural gas producers, ConocoPhillips is actively exploring for and developing new resources, such as in the Piceance Basin of western Colorado. Drilling began in 2006, with initial production achieved in July 2007. Here, ConocoPhillips plans hundreds of wells in a major, multi-year program to develop a basin-wide deposit of gas-bearing low-porosity rock.



that were on the high end of the cost curve. They accounted for only 1.5 percent of our volumes and had limited upside potential," Lowe says. "We plan ongoing sales that, combined with an inflow of new properties, assure the continual up-grading of our portfolio."

A Sound Strategic Direction

E&P is focused on transforming its substantial resource potential into proven reserves and ultimately production, and is pursuing new opportunities through focused exploration and business development. The company intends to achieve, on average, annual reserve replacement in excess of 100 percent; and an average annual production growth rate through 2012 of 2 percent.

The company's legacy assets, which include large operations in Alaska, repeatable drilling trends in the U.S. Lower 48 states and Canada, and long-life properties in the North Sea, represent a substantial and stable base of production. Growth is expected from the Athabasca oil sands, the Asia Pacific region, Russia and the Caspian Sea, the Middle East and Africa.

To enhance its exploration capabilities, E&P is working to supplement its traditional, low-risk drilling program with more high-risk, high-potential prospects. The process began with regional studies that identified such key focus areas as the Arctic, the deepwater Gulf of Mexico, the North Sea and offshore Australia. Increased acreage acquisitions in these areas began in 2007, with similar acquisitions and drilling expected to follow.

Meanwhile, E&P is responding to the challenging operating environment. While the entire industry is hampered by government-imposed restrictions on access to resources in many countries, E&P has the advantage of a substantial, existing opportunity portfolio primarily concentrated in relatively stable OECD countries.

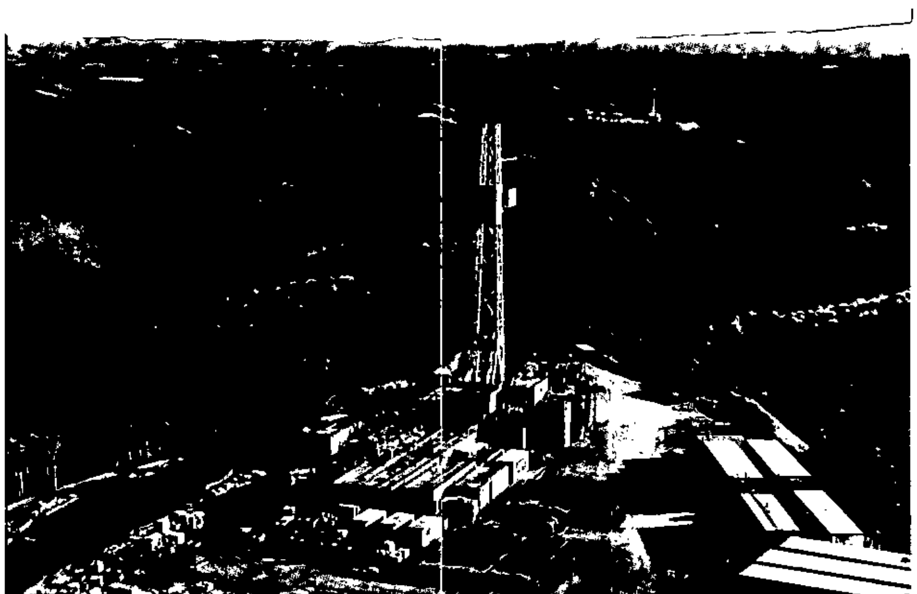
Industry cost inflation inevitably accompanies strong commodity prices. In response, E&P is leveraging its economies of scale in negotiating supply agreements, shortening project cycle times, employing new technology and selling underperforming assets.

"We continue to exercise strict capital discipline while conducting thorough analyses that enable us to fund the investments that add the greatest value," says Ryan Lance, president, E&P – Europe, Asia, Africa and the Middle East.

Looking toward the long term, ConocoPhillips continues striving to advance the construction of a natural gas pipeline from Alaska's North Slope, which would provide market access to significant gas resources. Additionally, the company supports the construction of a natural gas pipeline from Canada's Mackenzie Delta.

"Although the outlook for both pipelines remains uncertain, these natural gas supplies will be needed by North American markets in the future," Lowe says.

"In the meantime, our strong asset base, our strategic direction, and the opportunities we see in the market enable us to move into 2008 with a high level of confidence," he adds. "We are poised to continue our long-term growth and thereby build value for our shareholders."



Project Development

Transforming Opportunities Into Assets

2007 Major Accomplishments

- Completed the Kerisi project in Indonesia, which has a gross capacity of 50,000 barrels of oil per day (BOD) and 110 million cubic feet per day (MMCFD) of natural gas.
- Installed a new coker and vacuum unit at the Borger, Texas, refinery that will lower emissions, produce additional clean fuels and make the refinery more competitive.
- Achieved best-in-class safety performance by strengthening relationships with contractors, sharing best practices and technology, and promoting field participation from managers.

Diligent cost control and careful scheduling are key strategies employed by the company's Project Development business, which oversees nearly 40 major projects. An example is the Kerisi field development program in Indonesia, which achieved initial oil and natural gas production in December 2007.

Luc J. Messier
Senior Vice President, Project Development

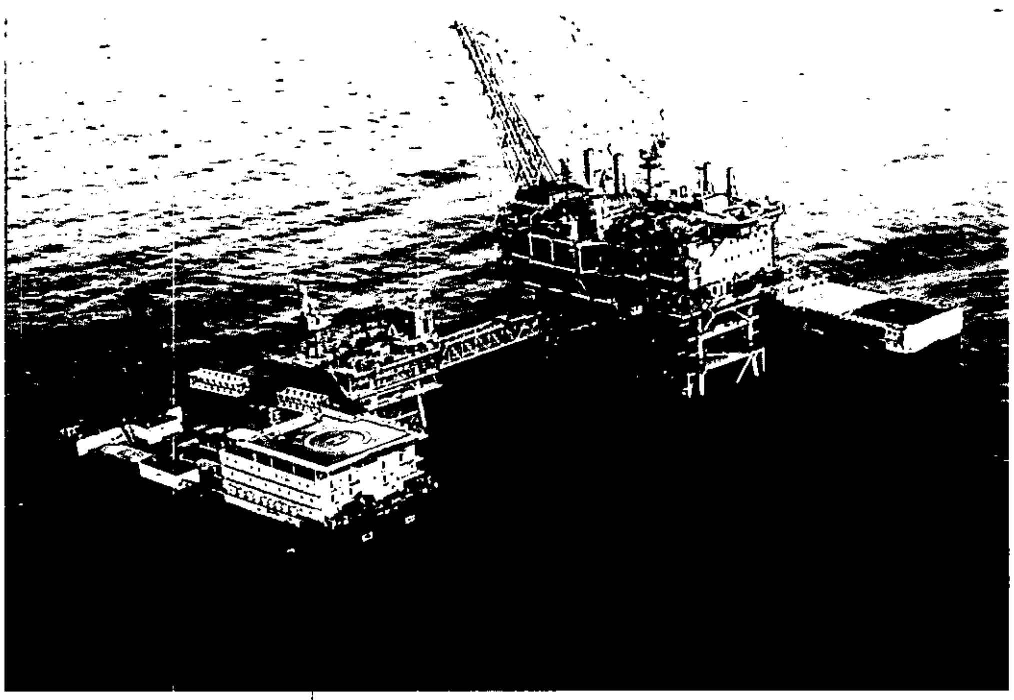
In 2007, the Project Development organization enhanced support of the company's upstream and downstream businesses with the introduction of "The ConocoPhillips Way" of doing projects – an improved capital project management system designed to consistently deliver the company's major projects safely, on time and within budget.

"To compete in the current market, we must complete projects in more challenging regions, using new technology and with strict environmental standards – all while managing the impact of rising costs and the intense competition for resources," says Luc Messier, senior vice president of Project Development. "The ConocoPhillips Way combines the company's best processes, skills, tools and technology into a flexible and efficient model that helps us deliver successful projects."

ConocoPhillips' major projects, primarily those with a capital investment greater than $75 million, present a high degree of complexity and are located worldwide. From the conceptual stage to the construction of the facilities, Project Development works in an integrated manner with the businesses and manages risks, engineering, procurement and construction.

Recognized as an industry leader in contractor safety technology, the Project Development organization achieved best-in-class safety performance in 2007 by strengthening relationships with contractors, sharing best practices and technology, and promoting field participation of project managers.

Several key upstream projects were progressed in 2007 including final installation, hook-up, commissioning and delivery of first production from the Kerisi field in Indonesia. The Kerisi facilities are designed with a gross capacity of 50,000 BOD and 110 MMCFD.



Downstream projects advanced during 2007 included the completed construction and safe startup of a new coker and vacuum unit at the Borger, Texas, refinery. The new facilities allow the refinery to lower emissions, produce additional clean fuels and become more competitive.

"We are committed to executing safe, transparent, predictable and competitive projects," Messier says. "We are putting the people and tools in place to help the company meet these challenges and build on a strong foundation of value-generating assets."

Refining and Marketing

Building Value by Transforming Hydrocarbons Into Consumer Products

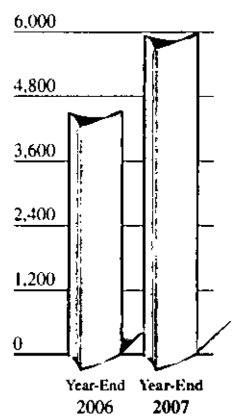
2007 Major Accomplishments

- Achieved record-breaking financial performance for the second year in a row with net income of $5.9 billion.
- Significantly exceeded refining industry utilization average in the United States with a utilization rate of 96 percent.
- Progressed several capital projects aimed at increasing clean fuels production and completed upgrades at the Borger, Texas, refinery. Construction is under way at the Rodeo facility of the San Francisco refinery and the Wood River refinery in Roxana, Ill.

Refining and Marketing Financial and Operating Results

	2007	2006
Net income (MM)	**$5,923**	$4,481
Crude oil throughput (MBD)	**2,560**	2,616
Crude oil capacity utilization	**94%**	92%
Clean product yield	**80%**	80%
Petroleum product sales (MBD)	**3,245**	3,476

Net Income for Refining and Marketing
(Millions of Dollars)



James L. Gallogly
Executive Vice President, Refining, Marketing and Transportation

Leveraging the company's integration of its R&M and E&P businesses, a new coker and vacuum unit at the Borger, Texas, refinery were completed in mid-2007 to improve capacity to process heavy oil from ConocoPhillips' oil sands ventures in Canada.

With U.S. refining utilization rates significantly above the industry average in 2007, ConocoPhillips' Refining and Marketing (R&M) business benefited from strong margins and operational results and achieved record-breaking financial performance for the second year in a row.

In addition, several newly completed strategic projects have positioned R&M for future profitability. A 50/50 business venture with EnCana Corporation was successfully initiated, comprised of a downstream limited liability company and an upstream partnership. The downstream company is anchored by the Wood River refinery in Roxana, Ill., and the Borger, Texas, refinery. Both are being modified to increase their capacity to process heavy crude oil from Canada, while the venture's upstream partnership provides long-term access to cost-advantaged crude oil.

During 2007, a new 25,000 barrel-per-day (BPD) coker and 75,000 BPD vacuum unit started up at the Borger refinery to process heavier crude oil and increase clean fuels production. The units meet regulatory requirements for low-sulfur fuels while also reducing emissions and lowering maintenance and operating costs. A debottlenecking project at the Ferndale, Wash., refinery increased its crude capacity by 4 percent and improved its energy efficiency.

"Operating excellence, cost control, margin enhancement and good portfolio management are vital to our competitive position and

ConocoPhillips continues upgrading several refineries in the United States and Europe to improve their economic performance and reduce their environmental impact. The Rodeo facility of the San Francisco refinery (pictured) is currently installing a new hydrocracker to process heavy, high-sulfur and thus cost-advantaged crude oil. The unit also will increase output of high-value clean fuels.

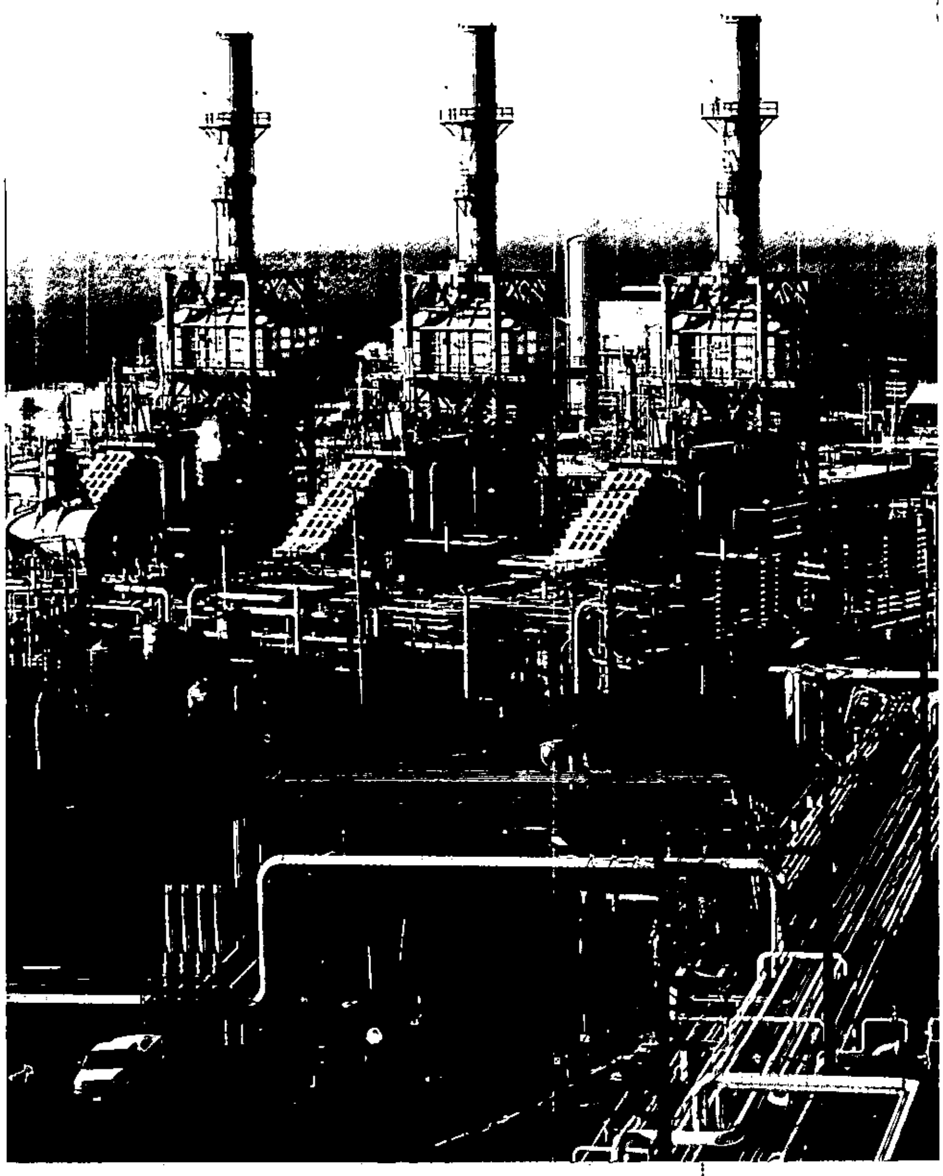
financial success," says Jim Gallogly, executive vice president, Refining, Marketing and Transportation. "We have a number of initiatives under way to gain maximum value from our existing assets while further improving our already-strong safety and environmental performance."

Safe, Reliable Operations

"Our operating excellence strategy is focused on ensuring that we operate safely and reliably while reducing our environmental impact," Gallogly says. "Operating excellence forms the basis for everything we do."

This emphasis resulted in improved employee safety performance in 2007. R&M is currently implementing enhanced standards for process and personal safety that focus on critical elements such as asset integrity inspections, facility siting, change management and incident investigations. A specialized team is auditing refining process safety to identify improvement opportunities and share best practices.

The company's focus on safety also is evident in the number of facilities that have qualified for "Star" status under the U.S. Occupational Safety & Health Administration's Voluntary Protection Program, which distinguishes work sites that achieve exemplary safety and health standards. The Bryan, Texas, Flow Improver facility and Sweeny, Texas, refinery earned this status in 2007, while the Wood River refinery and Gulf Coast Lubricants plant also were recommended for this status. The goal is for all of R&M's U.S. operating facilities to earn this distinguished certification.



High operating reliability helped R&M achieve a U.S. refining crude oil capacity utilization rate of 96 percent, exceeding the industry average for the sixth consecutive year, and a combined U.S. and international utilization rate of 94 percent. R&M has improved reliability through risk-reduction best practices, infrastructure modernization, operator training and key debottlenecking projects at several U.S. refineries.

R&M also is working to reduce the environmental impact of its refineries through projects to lower emissions of sulfur dioxide and nitrogen oxide more than 70 percent and 35 percent, respectively, by 2012. These include installation of flare gas recovery systems and modifications to heaters and fluid catalytic cracking units at the U.S. refineries. In addition, reductions in carbon dioxide emissions are being achieved through energy-efficiency improvements.

Water-use assessments were completed at several refineries in 2007, with more planned in 2008 to identify ways to recycle water and reduce fresh-water consumption.

R&M continues increasing its clean fuels production while incorporating more biofuels and renewable fuels into the refined products mix. In late 2007, the Borger refinery began producing renewable diesel fuel made from by-product animal fats through an alliance with Tyson Foods. Additionally, most of the U.S. product storage terminals have

Safety is a major focus for ConocoPhillips. The company continuously reviews its safety processes and procedures and provides hands-on training. During 2007, more than 200 emergency response personnel from refineries and other facilities participated in the third annual corporate fire school. Attendees received classroom instruction and practiced their emergency procedures and skills.

been upgraded to blend ethanol, and several are being upgraded to distribute biodiesel. In Europe, the Whitegate refinery in Ireland began producing renewable diesel fuel in 2006, and the company expects to increase sales of biofuels in European markets in 2008.

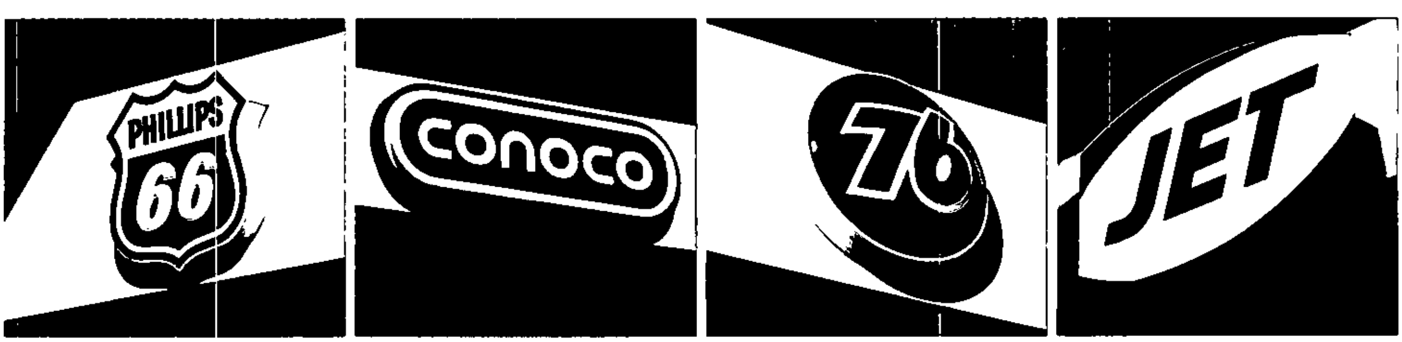
The company has completed the first phase of its clean fuels upgrades, centered on ultra-low-sulfur diesel fuel and low-sulfur gasoline. Future clean fuels projects will involve reducing the amount of benzene in gasoline.

Addressing the Rising Cost Environment

R&M continually optimizes its operations and asset portfolio to manage the impact of high inflation rates on its business. The disposition of certain nonstrategic transportation and marketing assets in the United States, Europe and Asia will result in the elimination of approximately $250 million in controllable costs going forward. These assets were divested during 2007 and in the first quarter of 2008. More than 750 U.S. retail sites also are planned for sale, allowing R&M to focus on the wholesale channel of trade to optimize sales volumes to desired refining integration levels.

Another way R&M manages costs is through increasing its capacity to process heavier, cost-advantaged crude oil. The new coker unit at the Borger refinery enables it to process heavy Canadian crude oil. A planned upgrade of the fractionator unit at the Billings, Mont., refinery also will increase heavy Canadian crude oil processing capacity, as well as improve efficiency and energy usage at the facility.

Energy consumption is one of R&M's biggest operating costs, and the business is incorporating efficiency improvements into its slate of capital projects. Efficiency initiatives at the Billings and Lake Charles, La., refineries earned the U.S. Environmental Protection Agency's Energy Star award for facilities that achieve top-quartile energy efficiency.



ConocoPhillips markets gasoline, diesel fuel and aviation fuel in the United States utilizing the Phillips 66®, Conoco® and 76® brands. Internationally, it markets its products primarily through JET® branded outlets.

Employing a strategy that was used successfully at its refineries in the United States, ConocoPhillips plans a major upgrading of the Wilhelmshaven refinery in Germany to improve the refinery's ability to process high-sulfur crude oil and produce low-sulfur clean fuels.

"The costs of materials, labor, feedstocks and other critical resources are rapidly increasing," Gallogly says. "We're adapting to this environment and controlling our costs by ensuring that our operations run as efficiently and reliably as possible."

Building on Our Base

R&M's capital investments are aimed at maintaining and enhancing existing refineries to increase their output of higher-value clean fuels, raise overall distillation capacity, and enable them to process heavier and higher-sulfur crude oils that are lower in cost. The company also is pursuing several major downstream growth opportunities to complement these enhancements.

"Through expansion projects at existing refineries over the next five years, we will add enough clean fuels production on a net basis to equal an average-sized new refinery," Gallogly says.

For example, a 20,000 BPD hydrocracker under construction at the Rodeo facility of the San Francisco refinery will increase clean fuels production by 12 percent and improve energy efficiency. Other projects are planned for the Ferndale, Los Angeles, Billings and Bayway refineries.

Through the joint venture with EnCana, a major expansion planned for the Wood River refinery will leverage the company's upstream position by more than doubling the refinery's capacity to process bitumen-based crude oil produced in Canada, while increasing overall crude oil capacity and clean product yields. Also, an investment in the proposed Keystone pipeline that will carry crude oil from Canada to the United States will further leverage ConocoPhillips' upstream position in Canada.

Several major international refining capital investments also are planned, including an upgrade project at the Wilhelmshaven refinery in Germany to enable it to process heavier, higher-sulfur crude oil and produce more low-sulfur diesel fuel and gasoline.

In Saudi Arabia, ConocoPhillips is working with Saudi Aramco on the development of a proposed new joint venture 400,000 BPD full-conversion refinery in Yanbu. The facility would process heavy crude oil into high-quality refined products for export into world markets. Plans also are proceeding to expand processing capacity at the Melaka joint-venture refinery in Malaysia by 20,000 net BPD.

"We are selectively investing in major projects that enhance opportunities for profitability and support the company's upstream business," Gallogly says. "In addition, our employees' commitment to continuous improvement in safety, environmental stewardship and reliability will help R&M retain its strong competitive advantage."

LUKOIL Investment

Growing Production and Refining Capacity in Russia

LUKOIL Financial and Operating Results (COP Net)*

	2007	2006
Net income (MM)	**$ 1,818**	$ 1,425
Net crude oil production (MBD)	**401**	360
Net natural gas production (MMCFD)	**256**	244
Net refining crude oil throughput (MBD)	**214**	179

**Represents ConocoPhillips' estimate of its weighted-average equity share of LUKOIL's income and selected operating statistics, based on current market indicators, publicly available LUKOIL operating results and other objective data.*

Crude oil produced by the Naryanmarneftegaz joint venture between ConocoPhillips and LUKOIL in the Timan-Pechora region of Russia will be shipped to worldwide markets through this LUKOIL terminal at Varandey Bay on the Barents Sea.

ConocoPhillips has 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.

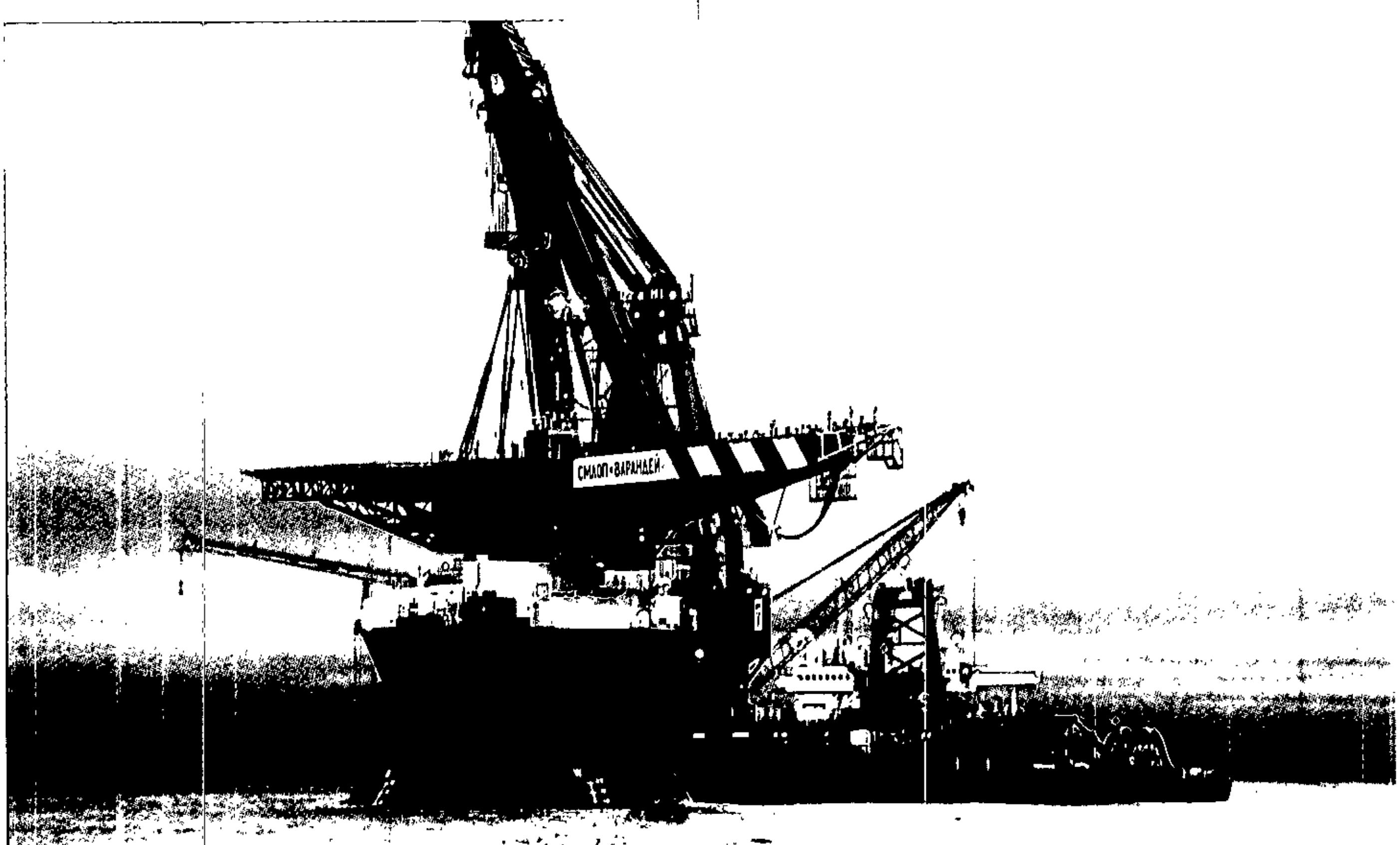
The company's cumulative investment in LUKOIL stock totaled $7.5 billion at year-end 2007, accounting for 19 percent of ConocoPhillips' 2007 daily barrel-of-oil-equivalent (BOE) production.

Additionally, ConocoPhillips and LUKOIL have partnered in the Naryanmarneftegaz joint venture, with startup of the large Yuzhno Khylchuyu field expected during 2008.

Approximately 30 employees are seconded between the companies to facilitate knowledge exchange, creating significant value through technology applications and business process improvements.

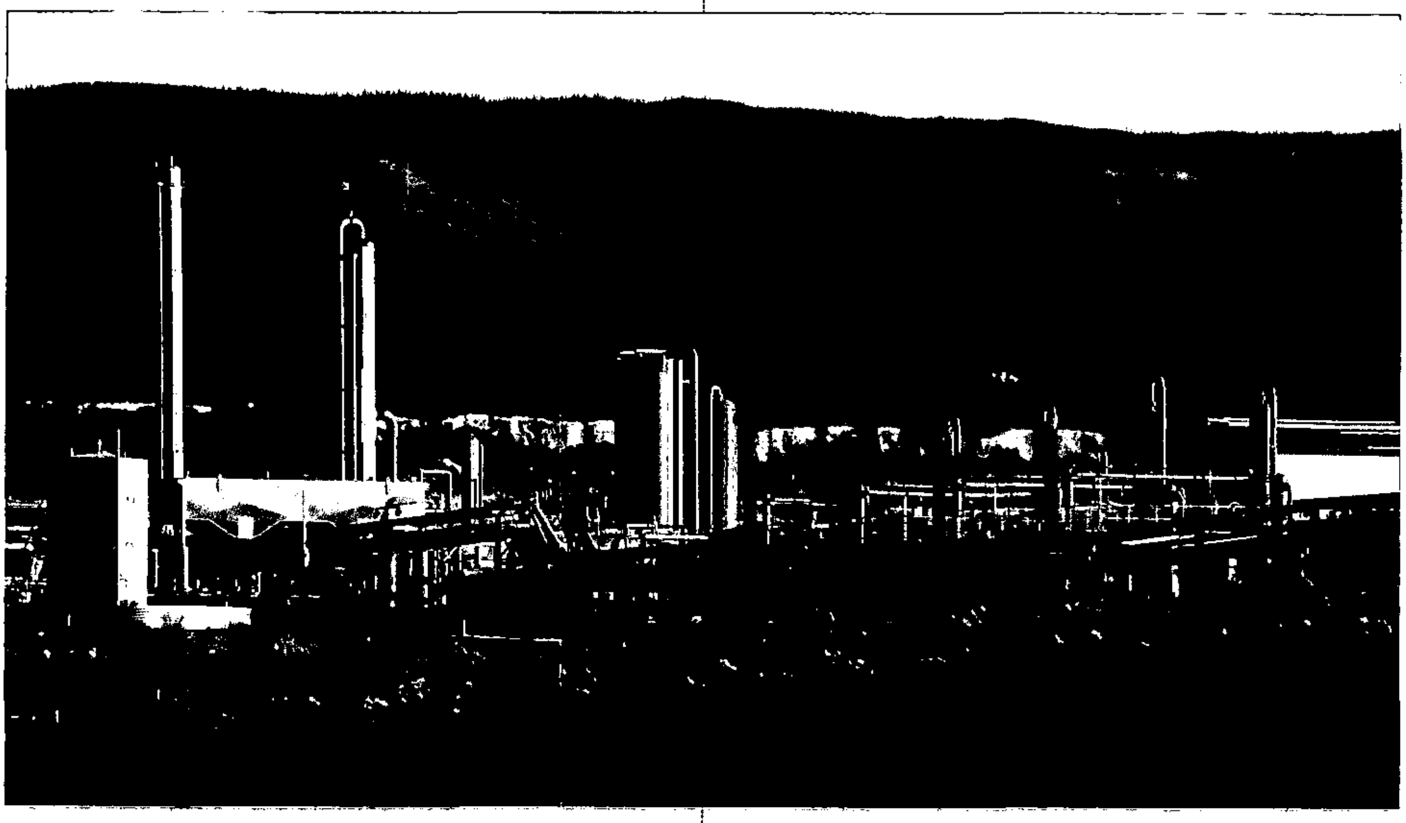
LUKOIL's 2007 milestones include the discovery of six new oil, natural gas and condensate fields and entry into a joint venture with GazpromNeft (Russia) that will open access to new ventures in several prospective areas. LUKOIL also commissioned a new natural gas field in Uzbekistan, as well as new facilities at refineries in Volgograd, Ukhta, Perm, Odessa and Romania.

ConocoPhillips' estimated share of LUKOIL's 2007 production was 444,000 BOE per day and refining crude oil throughput was 214,000 barrels per day.



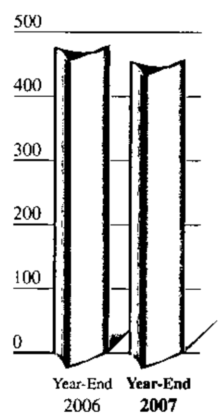
Midstream

Positioned for Growth in an Expanding Market



2007 Major Accomplishments

- DCP Midstream's master limited partnership, DCP Midstream Partners, completed its acquisition of natural gas gathering and compression assets in Oklahoma from Anadarko Petroleum Corporation for approximately $180 million.
- DCP Midstream contributed a 25 percent interest in DCP East Texas Holdings, LLC and a 40 percent interest in Discovery Producer Services LLC to DCP Midstream Partners for approximately $270 million.
- DCP Midstream and DCP Midstream Partners acquired Momentum Energy Group Inc. for approximately $635 million to expand into three prominent producing basins: Fort Worth, Piceance and Powder River.



Net Income for the Midstream Segment
(Millions of Dollars)

^ *Midstream expanded its gas gathering and processing capabilities in the rapidly developing Piceance Basin natural gas trend of western Colorado, where ConocoPhillips' E&P business unit also has a growing presence.*

During 2007 ConocoPhillips saw significant growth in DCP Midstream, LLC, a 50/50 joint venture with Spectra Energy. DCP Midstream is one of the largest U.S. natural gas and natural gas liquids gathering, processing and marketing companies.

Among the year's achievements, DCP Midstream and DCP Midstream Partners, the company's master limited partnership, completed more than $800 million in acquisitions. The company also expanded its presence in the Fort Worth, Piceance and Powder River Basins – all prominent developing producing areas.

"We have a solid operating performance base and a strong position for continued growth," says Thomas O'Connor, DCP's president, chairman and CEO. "We are pleased with the acquisitions and the potential they bring us."

ConocoPhillips' Midstream business also includes an equity interest in Phoenix Park Gas Processors Limited and interests in liquid extraction and fractionation plants in New Mexico, Texas, Louisiana and Kansas.

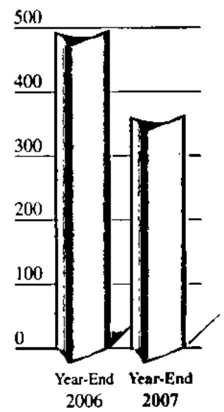
The ConocoPhillips Midstream segment's net income for 2007 was $453 million, with ConocoPhillips' net natural gas liquids extraction totaling 211,000 barrels per day (BD), including 181,000 BD from its interest in DCP Midstream. ConocoPhillips' share of DCP's raw natural gas throughput was 2.95 billion cubic feet per day.

Chemicals

Capitalizing on the Extended Hydrocarbon Value Chain

2007 Major Accomplishments

- CPChem broke ground on the construction of a 22 million pound-per-year Ryton® polyphenylene sulfide (PPS) manufacturing facility that will double the Borger, Texas, production capacity for the engineering polymer business.
- CPChem completed nearly 40 million work hours on CPChem's 50-percent-owned styrene facility at Al-Jubail, Saudi Arabia. Commercial production is expected to commence during the third quarter of 2008.
- CPChem completed nearly 30 million work hours on the Q-Chem II project, which includes world-scale, state-of-the-art, high-density polyethylene and normal alpha olefins plants at Mesaieed, Qatar, and a separate joint venture for an ethylene cracker at Ras Laffan Industrial City. The plant is expected to be completed during the first half of 2009.



Net Income for the Chemicals Segment
(Millions of Dollars)

Chevron Phillips Chemical Company LLC (CPChem), a joint venture in which ConocoPhillips owns a 50 percent interest, is valued for its ability to operate safely and reliably, deliver top value in its core businesses and advance major capital growth projects.

"These are exciting times for the company and our employees," said Ray Wilcox, president and chief executive officer of CPChem. "We are expanding investment activity abroad and doubling Ryton® PPS production domestically. That means more opportunities for our employees and an overall bright outlook for 2008."

In 2007, CPChem continued striving toward its goal of operating with zero injuries and incidents, finishing the year with a recordable incident rate of 0.56. CPChem also demonstrated its commitment to product and environmental sustainability by implementing numerous pollution-prevention and energy-efficiency projects at its facilities.

"Protecting our people and the environment is a way of life at CPChem," Wilcox said. "We strive to serve as good stewards of the environment not because we want to earn awards, but because it's the right thing to do."

In addition to safety and environmental performance, CPChem has made strides in profitability.

While the bulk of CPChem's earnings come from its North American petrochemicals business, the company is committed to international growth and development, particularly in the Middle East, where it already has a major operating facility in Qatar, two in Saudi Arabia, and three new projects starting up in the future.

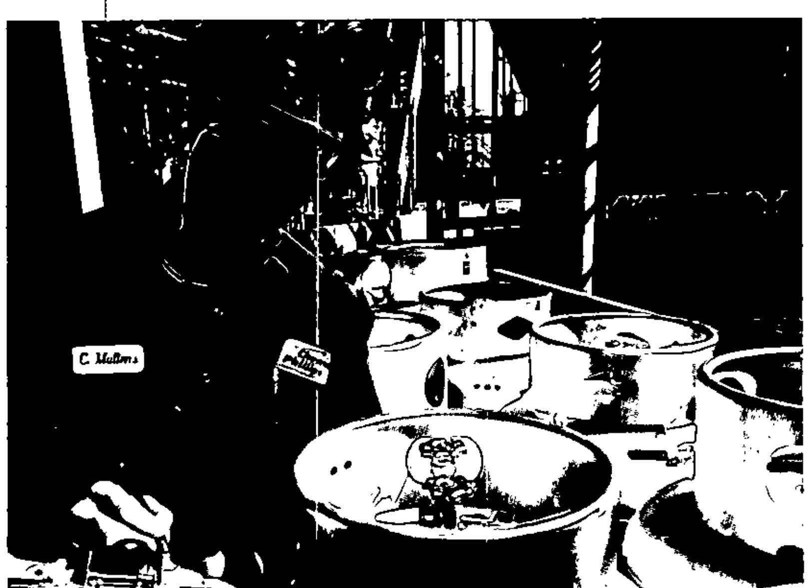
The company's new project in Saudi Arabia will produce benzene, ethylbenzene, styrene and propylene, and it is expected to begin commercial production during the third quarter of 2008.

The other project in Saudi Arabia will include a world-class olefins cracker and will produce ethylene, propylene, polyethylene, polypropylene, polystyrene and 1-hexene. It has received board of directors approval; engineering, procurement and construction agreements are in place; and the project is scheduled for commissioning in 2011.

CPChem's Q-Chem II project in Qatar will produce polyethylene and normal alpha olefins. It is currently under construction and expected to be commissioned during the first half of 2009.

"CPChem's Middle East operations play a significant and growing role in the company's success," Wilcox said. "The capital projects under way are key to our company's continued success and will provide us with reasonably priced feedstocks and access to growing markets."

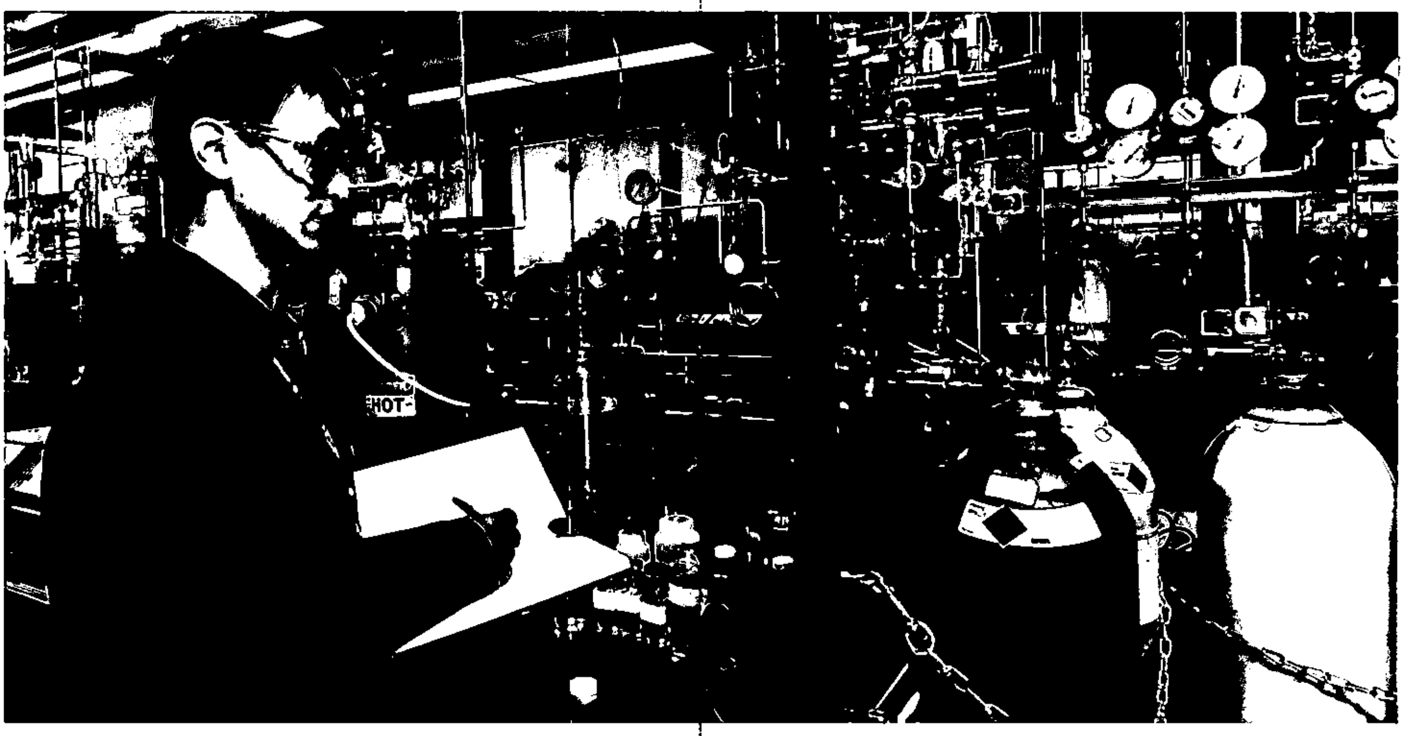
The ConocoPhillips Chemicals segment's net income for 2007 was $359 million, down from $492 million in 2006, reflecting lower olefins and polyolefins margins.



CPChem is one of the world's largest producers of petrochemicals with 11 facilities in the United States, including this one in Borger, Texas. Produced chemicals are used to manufacture more than 70,000 products in a number of industries, including the adhesive, automotive, healthcare and cosmetic industries.

Emerging Businesses

Developing Tomorrow's Energy Solutions



^ *The Emerging Businesses segment's research efforts focus on improving production of conventional fuels, as well as producing and commercializing alternative and renewable energy sources.*

Emerging Businesses invests in new technologies outside the company's normal scope of operations. Its activities are currently focused on carbon-to-liquids; technology solutions such as sulfur removal; alternative forms of energy such as advanced hydrocarbon processes, energy conversion technologies, new petroleum-based products and renewable fuels; and power generation.

"As an established conventional energy provider, ConocoPhillips also intends to be at the forefront of new, environmentally responsible energy resource development," says Stephen Brand, senior vice president, Technology. "We've increased our research and development activities in technologies that complement our existing businesses and provide strong growth opportunities in energy alternatives."

In 2007, ConocoPhillips and Tyson Foods announced an alliance to produce and market the next generation of renewable diesel fuel made by utilizing byproduct animal fat as a refining feedstock. Later that year, ConocoPhillips and Archer Daniels Midland announced a collaboration to research and commercialize renewable transportation fuels produced from biomass.

ConocoPhillips enhanced its heavy-oil production capabilities by entering into a venture with EnCana Corporation to produce and refine bitumen from the Athabasca oil sands. The company also is assessing the feasibility of producing shale oil in the U.S. Rocky Mountains and natural gas hydrates in arctic regions and beneath sea beds.

The company is researching technologies to reduce carbon dioxide emissions, including the proprietary ConocoPhillips E-Gas™ technology, which can convert coal into synthetic natural gas. A feasibility study with Peabody Energy is under way for a possible project that would produce pipeline-quality natural gas from proven U.S. coal reserves. Research also continues on carbon sequestration – capturing waste carbon dioxide and injecting it deep underground into depleted reservoirs, thus reducing atmospheric emissions.

Stephen R. Brand
Senior Vice President, Technology

Additionally, ConocoPhillips expanded its power business through acquisition and project development. In 2007, the company acquired a 50 percent interest in a cogeneration facility at its Sweeny refinery. It also made progress on phase II of the Immingham Combined Heat and Power (CHP) plant that will produce an incremental 450 megawatts of power and is scheduled to be completed in 2009. ConocoPhillips already owned the original Immingham CHP, a 730-megawatt, gas-fired combined heat and power plant located in North Lincolnshire, United Kingdom, as well as a 421-megawatt plant in Orange, Texas, that supplies steam and electricity.

Commercial

Ensuring Supply Reliability, Market Access and Maximum Value

The ConocoPhillips Commercial organization added significant value during 2007, successfully supporting the Exploration and Production and Refining and Marketing businesses with reliable supply and marketing activities, opportunistic commodity trading, and lending expertise on key asset optimizations and acquisitions.

Throughout the year, Commercial reliably secured the crude oil feedstock consumed by the company's 17 refineries while finding favorable markets for ConocoPhillips' own production of crude oil, natural gas and refined products.

"Despite the volatility and rising costs that characterize today's commodity markets, we continue to find ample opportunities to enhance our results through trading, storage, transportation and other related businesses," says Willie Chiang, senior vice president, Commercial.

The year's milestones included the expansion of its trading activities; growth in capacities for crude and product storage of four million barrels, natural gas of four billion cubic feet, marine transportation, pipeline transportation, and power generation; and increased usage under license of the proprietary ConocoPhillips E-Gas™ technology.

Trading expertise and knowledge of potential markets are vital in enabling the company to bid competitively for asset acquisitions and business development projects. During 2007 Commercial's capabilities helped ConocoPhillips acquire 50 percent interest in a cogeneration unit at the Sweeny refinery that supplies electricity to that facility and to the open market.

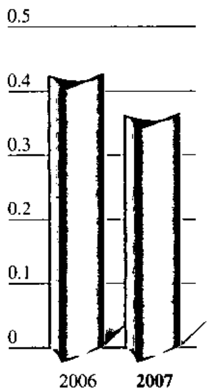
The group also secured capacity in the Keystone crude oil pipeline in Canada and the Rockies Express natural gas pipeline in the United States. Commercial's services were key in enabling development of the Immingham phase II heat and power plant in the United Kingdom and in securing an agreement with Peabody Energy to explore development of a coal gasification facility.

Striving to maximize margins, Patrick Chih, a trader in the Houston office, secures favorably priced gasoline blendstock for the company's refineries, and then seeks the best markets for its refined products. The fast-growing Commercial organization numbers 800 employees in Houston, Calgary, London, Dubai and Singapore. The group also manages the company's commodity portfolio.

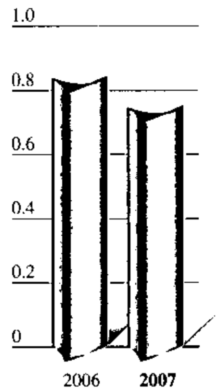
W.C.W. Chiang
Senior Vice President, Commercial

Corporate Staffs

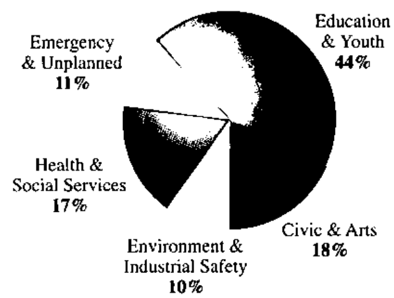
Employee Total Recordable Rate
(Total Company)



Contractor Total Recordable Rate
(Total Company)



$60 Million for 2007 Philanthropic Contributions



Legal

Providing Effective, Cost-Efficient Counsel

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

With personnel in 15 offices around the world, the ConocoPhillips Legal organization assists with the design and negotiation of company transactions, oversees corporate security, documents contractual arrangements, advises on commercial matters, protects intellectual property, defends litigation and prosecutes claims.

"We are a worldwide resource supporting ConocoPhillips businesses in nearly 40 countries," says Janet L. Kelly, senior vice president, Legal, general counsel and corporate secretary. "As members of project teams, our lawyers use their knowledge of local laws and legal systems, as well as their analytical, problem solving, negotiation and contract documentation expertise to enable the company to complete complex business transactions."

During 2007, the Legal organization assisted with more than 130 Exploration and Production projects around the globe and with the disposition of marketing assets in Europe and Southeast Asia.

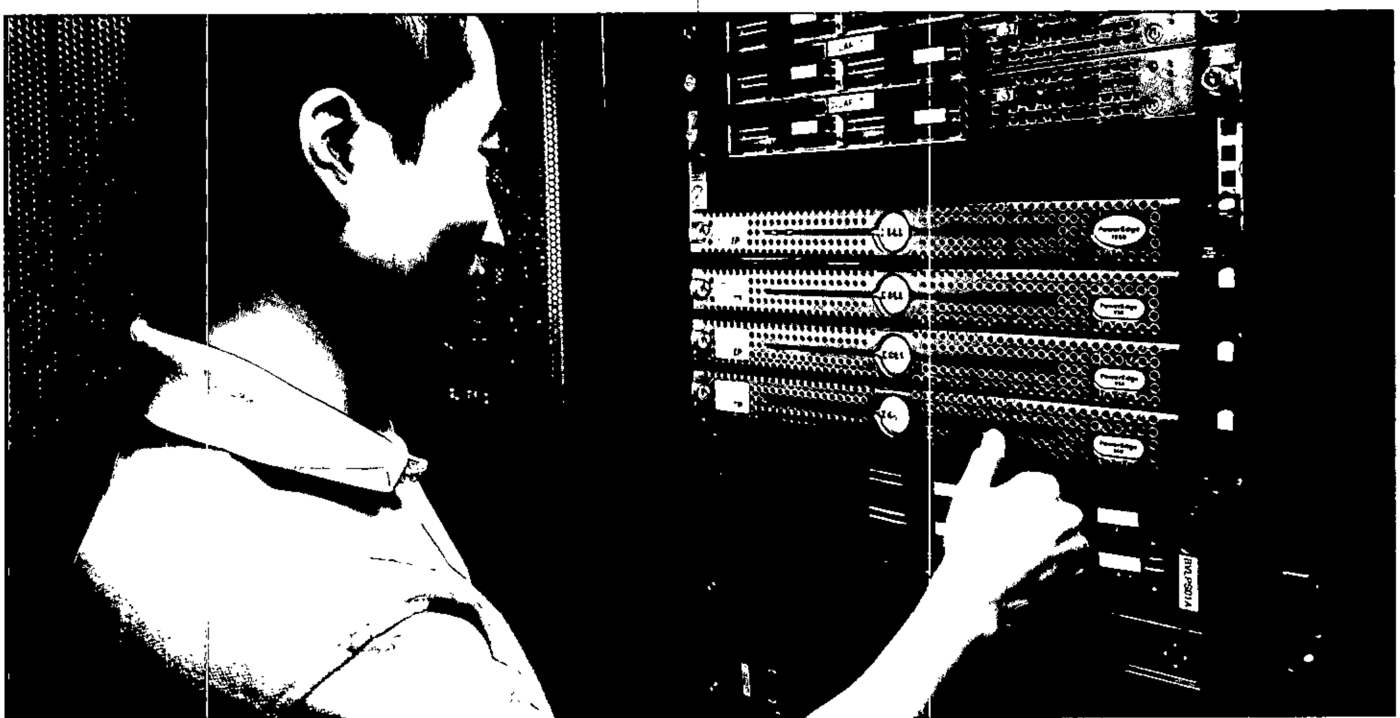
On a daily basis, the Legal staff provides real-time, practical support and leadership in the areas of compliance, ethics and corporate security.

Expectations for compliance with the law and ethical behavior are set by management and the board of directors, as set forth in the company's Code of Business Ethics and Conduct. The Legal staff provides training and counseling, with all employees required to participate in periodic training on the Code. To report any concerns, employees can contact management or call an ethics hotline.

Protecting employees and assets also is an ongoing focus for this organization. Its corporate security professionals make risk assessments, establish precautionary measures, respond to emergency situations and investigate claims.

"Our Legal organization is a critical partner in the success of ConocoPhillips around the world," Kelly says.

> Providing fast, reliable and compatible information systems is just one example of how Global Systems and Services enables the efficient operation of the company's worldwide businesses.



Global Systems and Services

Delivering Essential Business Services

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

By leveraging capabilities, Global Systems and Services (GSS) provides a variety of services essential to ConocoPhillips' worldwide businesses. Among these are aviation, real estate and facilities management, and financial and information services, all of which add value and help employees do their jobs better.

"We have one goal – deliver the right services at the right price at the right time," says Gene Batchelder, senior vice president, Services, and chief information officer.

Key 2007 achievements included substantial progress on integrating the former Burlington Resources operational and financial systems into ConocoPhillips' systems, an effort that yielded synergies well in excess of initial estimates. More than 30 associated projects are finished, with the completion of approximately six other projects expected during 2008.

Additionally, GSS completed a major upgrade of the SAP-based computer systems that perform such vital functions as financial records keeping, managing major capital development projects, scheduling plant maintenance, billing and materials tracking. The upgrade enables the company to more fully utilize the supporting SAP products and will facilitate their future integration with other critical systems.

Throughout the year, GSS worked to ensure that the company's U.S. assets – buildings, refineries, pipelines and mineral leases – were valued fairly and accurately on governmental tax rolls. This effort lowered annual tax obligations by $82 million, thus reducing pressure on operating costs.

To benefit two of its home communities in Oklahoma, ConocoPhillips built and populated company historical museums in Bartlesville and Ponca City, with GSS coordinating the design and construction of both the buildings and exhibits. Their openings were key events in Oklahoma's Centennial Celebration. The museums attracted more than 17,500 visitors during the year.

Also completed under GSS supervision were the construction of an employee wellness center, a parking garage and other facilities at the company's Houston headquarters.

"These achievements exemplify our efforts to meet the company's needs by providing services of such high quality and cost-effectiveness that they represent a competitive advantage for our business units," Batchelder says.

<< *The Legal organization provides support and guidance in a number of areas and subjects, including the storage and protection of company information.*

In the United States, ConocoPhillips supports the Department of Labor's Occupational Safety & Health Administration Voluntary Protection Program (VPP), which distinguishes work sites that achieve exemplary occupational safety and health standards. Several ConocoPhillips sites have achieved VPP "Star" recognition, including this one in Farmington, N.M.

Health, Safety and Environment

Dedicated to Safe Operations and Sound Stewardship

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

ConocoPhillips took significant steps in 2007 to strengthen its safety and environmental performance.

The company's total recordable rate (TRR) for employees and contractors improved by 10 percent over 2006; however, there were three contractor fatalities.

"The loss of lives on the job is unacceptable," says Bob Ridge, vice president, Health, Safety and Environment (HSE). "We are working continuously to improve our safety processes, training and policies to ensure that every worker returns home safely at the end of the day."

Throughout the year, the company reviewed its process safety management systems to identify improvement opportunities and initiated the HSE Excellence Process to help ensure that elements of the HSE Management System are effectively implemented throughout the company. The process builds on the principle that all incidents are preventable and that HSE considerations must be embedded into every task and business decision.

ConocoPhillips also strives to minimize the environmental, technological and economic impact of its operations. For example, the company monitors its freshwater consumption in order to develop strategies for reuse, identify and utilize nonconventional sources where supplies are scarce, and improve the quality of water produced or discharged. In Qatar, ConocoPhillips is sponsoring a water sustainability center that will become a corporate center of excellence for water-related technologies, providing services to the company's businesses worldwide and to the Qatari people. The company also is progressing toward its goal of improving energy efficiency at its U.S. refineries by 10 percent by 2012.

In 2007, ConocoPhillips made several key environmental announcements. The company joined both the World Bank's Global Gas Flaring Reduction partnership and the U.S. Climate Action Partnership, a business-environmental leadership group dedicated to the quick enactment of strong national legislation to require significant reductions of greenhouse gas emissions. Additionally, the company now incorporates the potential long-term cost of carbon into its capital spending plans.

"We believe that we can fulfill our primary mission of providing reliable supplies of energy while also demonstrating environmental responsibility and leadership," Ridge says.

Human Resources

Developing Employees' Full Potential

Carin S. Knickel
Vice President, Human Resources

Talented employees are the key to value creation and growth at ConocoPhillips. We believe that the creativity, commitment, knowledge and skill of our employees can enable differential business outcomes.

"Human Resources plays a critical role in developing and delivering the people strategies that drive our success," said Carin Knickel, vice president, Human Resources. "We partner with the business units to identify individuals with superior talent and provide a framework for effective performance management and development. The result is a work force capable of sustaining and growing our business."

To overcome an industry-wide shortage of qualified technical personnel, ConocoPhillips increased its emphasis on recruiting both recent college graduates and experienced personnel. Members of

ConocoPhillips provides employees with ongoing opportunities to enhance their skills through formal training and comprehensive personal development planning. >>

> Fostering a dialogue on energy, ConocoPhillips executives traveled to 35 U.S. cities to discuss issues and hear the views of the public. Here, Dewayne Black, manager, long-range projects, Technology, answers energy questions.

management from throughout the company participated in the recruitment process, which succeeded in hiring approximately 2,900 new employees during 2007 to bring the total work force to 32,600 at year end. The company also employed 415 interns in key areas, building a base of potential future employees.

Throughout an employee's career, professional development opportunities are made available. During 2007, $47 million was invested in training with approximately 33 percent of non-store employees receiving developmental and technical training and nearly 88 percent participating in organized training activities.

"As a result of these efforts, we believe that ConocoPhillips has exceptional individuals and teams in place in all our businesses with the professional development tools to ensure that they reach their full potential," Knickel says. "We are confident that our people are ready for the challenges of the future."

Planning, Strategy and Corporate Affairs

Providing Strategic Direction and a Public Voice

Sigmund L. Cornelius
Senior Vice President, Planning, Strategy and Corporate Affairs

Planning, Strategy and Corporate Affairs (PS&CA) actively engages the external community, including investors, the public, government and media; pursues development and execution of strategic ventures; enriches the community through charitable investment and employee volunteerism; and conducts economic and industry research and planning.

During 2007, the organization helped structure agreements with Archer Daniels Midland to collaborate on the development of renewable transportation fuels from biomass and with Tyson Foods to produce and market renewable diesel fuel. Both would supplement traditional petroleum-based supplies.

"In addition to providing reliable energy, the public expects us to serve as a good corporate citizen and a responsible member of the community," said Sigmund Cornelius, senior vice president, PS&CA. "We understand our social contract with our communities and take pride in our involvement."

The organization helped position the company to address the emerging climate-change issue. In 2007, ConocoPhillips became the first major U.S. oil company to join the U.S. Climate Action Partnership, which supports creation of a mandatory national framework to address greenhouse gas emissions. The company also pledged $1 million for the Climate Change Policy Partnership at Duke University, a four-year, university-industry collaboration to develop remedial policies.

PS&CA developed and coordinated public education through outreach initiatives that included new advertising and the Conversation on Energy community outreach program. Launched in late 2006, this program featured town hall meetings in 35 U.S. cities at which the public and ConocoPhillips executives discussed energy challenges and solutions. ConocoPhillips gained key insights into the public's energy preferences, and opinion surveys indicate that the program improved public perceptions of the company. This initiative is expected to continue in 2008.

Additionally, ConocoPhillips worked to enhance the well-being of the communities in which it operates throughout the world. Employees devoted thousands of hours of their time to worthy charitable, educational and civic activities. The company's 2007 philanthropic contributions were about $60 million.

Financial and Operating Results

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

February 21, 2008

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 53.

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 32,600 employees worldwide, and at year-end 2007 had assets of $178 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, primarily 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 (LUKOIL), an international, integrated oil and gas company headquartered in Russia. At December 31, 2007, our ownership interest was 20 percent based on issued shares, and 20.6 percent based on estimated shares outstanding.
- **Chemicals** — This segment manufactures and markets petrochemicals and plastics on a worldwide basis. The Chemicals segment consists of our 50 percent equity investment in Chevron Phillips Chemical Company LLC (CPChem).
- **Emerging Businesses** — This segment represents our investment in new technologies or businesses outside our normal scope of operations.

Crude oil and natural gas prices, along with refining margins, are the most significant factors in our profitability. Accordingly, our overall earnings depend primarily upon the profitability of our E&P and R&M segments. Crude oil and natural gas prices, along with refining margins, are driven by market factors over which we have no control. However, from a competitive perspective, there are other important factors we must manage well to be successful, including:

- **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 2007, our worldwide refinery capacity utilization rate was 94 percent, compared with 92 percent in 2006. The improved utilization rate reflects less scheduled downtime and unplanned weather-related downtime. Concerning the environment, we strive to conduct our operations in a manner consistent with our environmental stewardship principles.
- **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. The acquisition of Burlington Resources in March 2006 added approximately 2 billion barrels of oil equivalent to our proved reserves, and through our investments in LUKOIL during 2004, 2005 and 2006, we added about 1.9 billion barrels of oil equivalent. On January 3, 2007, we closed on a business venture with EnCana Corporation (EnCana). As part of this transaction, we added approximately 400 million barrels of oil equivalent to our proved reserves in 2007. In the three years ending December 31, 2007, our reserve replacement was 186 percent, including the impact of the Burlington Resources acquisition, our additional equity investment in LUKOIL, the EnCana business venture, 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 and prudently managing our capital program, within the context of our commitment to safety and environmental stewardship, are high priorities. We monitor these costs using various methodologies that are reported to senior management monthly, on both an absolute-dollar basis and a per-unit basis. Because managing operating and overhead costs are critical to maintaining competitive positions in our industries, cost control is a component of our variable compensation programs.

  With the rise in commodity prices over the last several years, and the subsequent increase in industry-wide spending on capital and major maintenance programs, we and other energy companies are experiencing inflation for the costs of certain goods and services in excess of general worldwide inflationary trends. Such costs include rates for drilling rigs, steel and other raw materials, as well as costs for skilled labor. While we work to manage the effect these inflationary pressures have on our costs, our capital program has been impacted by these factors. The continued weakening of the U.S. dollar has also contributed to higher costs. Our capital program may be further impacted by these factors going forward.
- **Selecting the appropriate projects in which to invest our capital dollars.** We participate in capital-intensive industries. As a result, we must often invest significant capital dollars to explore for new oil and gas fields, develop newly discovered fields, maintain existing fields, or continue to maintain and improve our refinery complexes. We invest in those projects that are expected to provide an adequate financial return on invested dollars. However, there are often long lead times from the time we make an investment to the time that investment is operational and begins generating financial returns.

  In January 2007, we entered into two 50/50 business ventures with EnCana to create an integrated North American heavy-oil business, consisting of a Canadian upstream general partnership, FCCL Oil Sands Partnership (FCCL), and a U.S. downstream limited liability company, WRB Refining LLC (WRB). We are obligated to contribute $7.5 billion, plus accrued interest, to FCCL over a 10-year period beginning in 2007. EnCana is obligated to contribute $7.5 billion, plus accrued interest, to WRB over a 10-year period beginning in 2007.

  Our capital expenditures and investments in 2007 totaled $11.8 billion, and we anticipate capital expenditures and investments to be approximately $14.3 billion in 2008. In addition to our capital program, we increased shareholder distributions in 2007 through a combination of increased dividends and share repurchases. Our cash dividends totaled $1.64 per share in 2007, an increase of 14 percent over $1.44 per share in 2006. We repurchased $7 billion of our common stock in 2007 and have $10 billion of share repurchase authority remaining through 2008.
- **Managing our asset portfolio.** We continue to evaluate opportunities to acquire assets that will contribute to future growth at competitive prices. We also continually assess our assets to determine if any no longer fit our strategic plans and should be sold or otherwise disposed. This management of our asset portfolio is important to ensuring our long-term growth and maintaining adequate financial returns. During 2006, we increased our investment in LUKOIL, ending the year with a 20 percent ownership interest based on issued shares. During 2006, we completed the $33.9 billion acquisition of Burlington Resources. Also during 2006, we announced the commencement of an asset rationalization program to evaluate our asset base to identify those assets that may no longer fit into our strategic plans or those that could bring more value by being monetized in the near term. This program generated proceeds of approximately $3.8 billion through December 31, 2007. In 2008, we expect to complete the disposition of our retail assets in the United States, Norway, Sweden and Denmark. We will evaluate additional opportunities to optimize and strengthen our asset portfolio as the year progresses.
- **Hiring, 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. In 2007, we hired approximately 2,900 new employees around the world, including university hires as well as experienced hires. 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. The ongoing hiring and training of employees is especially important given the significant number of experienced technical personnel potentially exiting the workplace over the next few years.

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

Other significant factors that can affect our profitability include:

- **Property and leasehold impairments.** As mentioned above, we participate in capital-intensive industries. At times, these investments become impaired when our reserve estimates are revised downward, when crude oil or natural gas prices, or refinery margins decline significantly for long periods of time, or when a decision to dispose of an asset leads to a write-down to its fair market value. Property impairments in 2007, excluding the impairment of expropriated assets, totaled $442 million, compared with $383 million in 2006. 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.
- **Goodwill.** As a result of mergers and acquisitions, at year-end 2007 we had $29.3 billion of goodwill on our balance sheet, compared with $31.5 billion of goodwill at year-end 2006. Although our latest tests indicate that no goodwill impairment is currently required, future deterioration in market conditions could lead to goodwill impairments that would have a substantial negative, though non-cash, effect on our profitability.
- **Effective tax rate.** Our operations are located in countries with different tax rates and fiscal structures. Accordingly, even in a stable commodity price and fiscal/regulatory environment, our overall effective tax rate can vary significantly between periods based on the "mix" of pretax earnings within our global operations.

- **Fiscal and regulatory environment.** As commodity prices and refining margins improved over the last several years, certain governments have responded with changes to their fiscal take. These changes have generally negatively impacted our results of operations, and further changes to government fiscal take could have a negative impact on future operations. In June 2007, our Venezuelan oil projects were expropriated, and we recorded a $4,588 million before-tax ($4,512 million after-tax) impairment (see the "Expropriated Assets" section of Note 13 — 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. Also in October 2007, the Alberta provincial government publicly announced its intention to change the royalty structure for Crown lands, effective January 1, 2009 (see the "Outlook" section for additional information on the proposed royalty increase). In January 2008, we and our co-venturers agreed to 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, subject to completion of definitive agreements on dilution and other matters.

  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 were higher in 2007 compared with 2006, averaging $72.25 per barrel in 2007, an increase of 9 percent. The increase was primarily due to growth in global consumption associated with continuing economic expansions and limited spare capacity from major exporting countries. Industry natural gas prices for Henry Hub increased during 2007, primarily due to increased demand from the residential and electric power sector. These factors were moderated by higher domestic production, increased LNG imports, and high storage levels.

The Midstream segment's results are most closely linked to natural gas liquids prices. The most important factor on the profitability of this segment is the results from our 50 percent equity investment in DCP Midstream. During 2005, we increased our ownership interest in DCP Midstream from 30.3 percent to 50 percent, and we recorded a gain of $306 million, after-tax, for our equity share of DCP Midstream's sale of its general partnership interest in TEPPCO Partners, LP (TEPPCO). DCP Midstream's natural gas liquids prices increased 19 percent in 2007.

Refining margins, refinery utilization, cost control, and marketing margins primarily drive the R&M segment's results. Refining margins are subject to movements in the cost of crude oil and other feedstocks, and the sales prices for refined products, which are subject to market factors over which we have no control. Industry refining margins in the United States were stronger overall in comparison to 2006. Key factors contributing to the stronger refining margins in 2007 were lower industry refining utilization in the United States and higher distillate and gasoline demand. Wholesale marketing margins in the United States were lower in 2007, compared with those in 2006, as the market did not generally keep pace with the rising cost of crude oil.

The LUKOIL Investment segment consists of our investment in the ordinary shares of LUKOIL. In October 2004, we closed on a transaction to acquire 7.6 percent of LUKOIL's shares from the Russian government for approximately $2 billion. During the remainder of 2004, all of 2005 and 2006, we invested an additional $5.5 billion, bringing our equity ownership interest in LUKOIL to 20 percent by year-end 2006, based on issued shares. At December 31, 2007, our ownership interest was 20 percent based on issued shares and 20.6 percent based on estimated shares outstanding. We initiated this strategic investment to gain further exposure to Russia's resource potential, where LUKOIL has significant positions in proved reserves and production. We benefited from an increase in proved oil and gas reserves at an attractive cost, and our E&P segment should benefit from direct participation with LUKOIL in large oil projects in the northern Timan-Pechora province of Russia, and potential opportunities for participation in other developments.

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 other items, such as carbon-to-liquids, technology solutions, and alternative energy and programs, such as advanced hydrocarbon processes, energy conversion technologies, new petroleum-based products, and renewable fuels. Some of these technologies may have the potential to become important drivers of profitability in future years.

Results of Operations

Consolidated Results

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

Years Ended December 31	Millions of Dollars		
	2007	2006	2005
Exploration and Production (E&P)	**$ 4,615**	9,848	8,430
Midstream	**453**	476	688
Refining and Marketing (R&M)	**5,923**	4,481	4,173
LUKOIL Investment	**1,818**	1,425	714
Chemicals	**359**	492	323
Emerging Businesses	**(8)**	15	(21)
Corporate and Other	**(1,269)**	(1,187)	(778)
Net income	**$11,891**	15,550	13,529

2007 vs. 2006

The lower results in 2007 were primarily the result of:

- The complete impairment ($4,512 million after-tax) of our oil interests in Venezuela resulting from their expropriation in June 2007.
- Lower crude oil production in the E&P segment.
- Decreased net income from the Chemicals segment, primarily due to lower olefins and polyolefins margins.
- 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.

2006 vs. 2005

The improved results in 2006, compared with 2005, were primarily the result of:

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

These items were partially offset by:

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

Income Statement Analysis

2007 vs. 2006

Equity in earnings of affiliates increased 21 percent in 2007. The increase reflects earnings from WRB Refining LLC and FCCL Oil Sands Partnership, 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 in Venezuela, primarily due to the expropriation of our interests during 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 of escrowed funds related to the extinguishment of Hamaca project financing.
- The settlement of retroactive adjustments for crude oil quality differentials on Trans-Alaska Pipeline System shipments (Quality Bank) 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 (DD&A) 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.

Impairment — expropriated assets reflects a non-cash impairment of $4,588 million before-tax related to the expropriation of our oil interests in Venezuela recorded in the second quarter of 2007. For additional information, see the "Expropriated Assets" section of Note 13 — Impairments, in the Notes to Consolidated Financial Statements.

Impairments, which excludes the expropriation of our oil interests in Venezuela, decreased 35 percent during 2007, primarily due to the significant 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. See Note 13 — Impairments, in the Notes to Consolidated Financial Statements, for additional information.

Interest and debt expense increased 15 percent during 2007, primarily due to the interest expense component of the 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.

Our effective tax rate in 2007 was 49 percent, compared with 45 percent in 2006. The change in the effective rate for 2007 was primarily due to the impact of the expropriation of our oil interests in Venezuela in the second quarter of 2007. This impact was partially offset by the effect of income tax law changes enacted during 2007, and by a higher proportion of income in higher tax rate jurisdictions during 2006.

2006 vs. 2005

Sales and other operating revenues increased 2 percent in 2006, compared with 2005, while purchased crude oil, natural gas and products decreased 5 percent. The increase in sales and other operating revenues was primarily due to higher realized prices for crude oil and petroleum products, as well as higher sales volumes associated with the Burlington Resources acquisition. These increases were mostly offset by decreases associated with the implementation of Emerging Issues Task Force Issue No. 04-13, "Accounting for Purchases and Sales of Inventory with the Same Counterparty." The decrease in purchased crude oil, natural gas and products was primarily the result of the implementation of Issue No. 04-13. See Note 2 — Changes in Accounting Principles, in the Notes to Consolidated Financial Statements, for additional information on the impact of this Issue on our income statement.

Equity in earnings of affiliates increased 21 percent in 2006, compared with 2005. The increase reflects improved results from:

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

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

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

Production and operating expenses increased 22 percent in 2006, compared with 2005. The increase was primarily due to the acquired Burlington Resources assets, increased production at the Bayu-Undan field associated with the Darwin liquefied natural gas (LNG) project in Australia, the first year of production in Libya, and the acquisition of the Wilhelmshaven refinery in Germany.

Exploration expenses increased 26 percent in 2006, compared with 2005, primarily due to the Burlington Resources acquisition.

DD&A increased 71 percent during 2006, compared with 2005. The increase was primarily the result of the addition of Burlington Resources assets in E&P's depreciable asset base. In addition, the acquisition of the Wilhelmshaven refinery increased DD&A recorded by the R&M segment.

Impairments were $683 million in 2006, compared with $42 million in 2005. The increase primarily relates to the impairment in 2006 of certain assets held for sale in the R&M and E&P segments. We also recorded an impairment charge in the E&P segment associated with assets in the Canadian Rockies Foothills area.

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

Restructuring Program

As a result of the acquisition of Burlington Resources, we implemented a restructuring program in March 2006 to capture the synergies of combining the two companies. Under this program, we recorded accruals totaling $230 million in 2006 for employee severance payments, site closings, incremental pension benefit costs associated with the workforce reductions, and employee relocations. Approximately 600 positions were identified for elimination, most of which were in the United States.

Of the total accrual, $224 million was reflected in the Burlington Resources purchase price allocation as an assumed liability, and $6 million ($4 million after-tax) related to ConocoPhillips was reflected in selling, general and administrative expenses in 2006. Included in the total accruals of $230 million was $12 million related to pension benefits to be paid in conjunction with other retirement benefits over a number of future years. See Note 6 — Restructuring, in the Notes to Consolidated Financial Statements, for additional information.

Segment Results
E&P

	2007	2006	2005
	Millions of Dollars		
Net Income			
Alaska	**$2,255**	2,347	2,552
Lower 48	**1,993**	2,001	1,736
United States	**4,248**	4,348	4,288
International	**367**	5,500	4,142
	$4,615	9,848	8,430
	Dollars Per Unit		
Average Sales Prices			
Crude oil (per barrel)			
United States	**$68.00**	61.09	51.09
International	**70.79**	63.38	52.27
Total consolidated	**69.47**	62.39	51.74
Equity affiliates*	**45.31**	46.01	37.79
Worldwide E&P	**67.11**	60.37	49.87
Natural gas (per thousand cubic feet)			
United States	**5.98**	6.11	7.12
International	**6.51**	6.27	5.78
Total consolidated	**6.26**	6.20	6.32
Equity affiliates*	**.30**	.30	.26
Worldwide E&P	**6.26**	6.19	6.30
Natural gas liquids (per barrel)			
United States	**46.00**	40.35	40.40
International	**48.80**	42.89	36.25
Total consolidated	**47.13**	41.50	38.32
Equity affiliates*	—	—	—
Worldwide E&P	**47.13**	41.50	38.32
Average Production Costs Per Barrel of Oil Equivalent			
United States	**$ 6.52**	5.43	4.24
International	**7.68**	5.65	4.58
Total consolidated	**7.13**	5.55	4.43
Equity affiliates*	**8.92**	5.83	4.93
Worldwide E&P	**7.21**	5.57	4.47

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

	2007	2006	2005
	Millions of Dollars		
Worldwide Exploration Expenses			
General administrative, geological and geophysical, and lease rentals	**$ 544**	483	312
Leasehold impairment	**254**	157	116
Dry holes	**209**	194	233
	$1,007	834	661

	2007	2006	2005
	Thousands of Barrels Daily		
Operating Statistics			
Crude oil produced			
Alaska	**261**	263	294
Lower 48	**102**	104	59
United States	**363**	367	353
Europe	**210**	245	257
Asia Pacific	**87**	106	100
Canada	**19**	25	23
Middle East and Africa	**81**	106	53
Other areas	**10**	7	—
Total consolidated	**770**	856	786
Equity affiliates*			
Canada	**27**	—	—
Russia and Caspian	**15**	15	15
Venezuela	**42**	101	106
	854	972	907
Natural gas liquids produced			
Alaska	**19**	17	20
Lower 48	**79**	62	30
United States	**98**	79	50
Europe	**14**	13	13
Asia Pacific	**14**	18	16
Canada	**27**	25	10
Middle East and Africa	**2**	1	2
	155	136	91
	Millions of Cubic Feet Daily		
Natural gas produced**			
Alaska	**110**	145	169
Lower 48	**2,182**	2,028	1,212
United States	**2,292**	2,173	1,381
Europe	**961**	1,065	1,023
Asia Pacific	**579**	582	350
Canada	**1,106**	983	425
Middle East and Africa	**125**	142	84
Other areas	**19**	16	—
Total consolidated	**5,082**	4,961	3,263
Equity affiliates*			
Venezuela	**5**	9	7
	5,087	4,970	3,270
	Thousands of Barrels Daily		
Mining operations			
Syncrude produced	**23**	21	19

**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, 2007, our E&P operations were producing in the United States, Norway, the United Kingdom, the Netherlands, Canada, Nigeria, Ecuador, Argentina, offshore Timor-Leste in the Timor Sea, Australia, China, Indonesia, Algeria, Libya, Vietnam, and Russia.

2007 vs. 2006

Net income from the E&P segment decreased 53 percent in 2007. In the second quarter of 2007, we recorded a non-cash impairment of $4,588 million before-tax ($4,512 million after-tax) related to the expropriation of our oil interests in Venezuela. For additional information, see the "Expropriated Assets" section of Note 13 — Impairments, in the Notes to Consolidated

Financial Statements, which is incorporated herein by reference. 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 Quality Bank settlements.

If crude oil prices in 2008 do not remain at the levels experienced in 2007, and if costs continue to increase, the E&P segment's earnings would be negatively impacted. See the "Business Environment and Executive Overview" section for additional information on industry crude oil and natural gas prices and inflationary cost pressures.

Proved reserves at year-end 2007 were 8.72 billion barrels of oil equivalent (BOE), compared with 9.36 billion BOE 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 mining operations, which was 221 million barrels at year-end 2007, compared with 243 million barrels 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 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 BOE per day in 2006. Production was impacted by the inclusion of the Burlington Resources assets for the full year of 2007, offset slightly by normal 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 BOE per day 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 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 barrels per day in 2006.

2006 vs. 2005

Net income from the E&P segment increased 17 percent in 2006, compared with 2005. The increase was primarily due to higher realized crude oil prices and, to a lesser extent, higher sales prices for natural gas liquids and Syncrude. In addition, increased sales volumes, primarily the result of the Burlington Resources acquisition, contributed positively to net income in 2006. These items were partially offset by lower realized natural gas prices, higher exploration expenses, the negative impacts of changes in tax laws, and asset impairments.

U.S. E&P

Net income from our U.S. E&P operations increased slightly in 2006, compared with 2005, primarily resulting from higher crude oil prices, as well as increased crude oil, natural gas, and natural gas liquids production in the Lower 48 states, reflecting the Burlington Resources acquisition. These increases were partially offset by lower natural gas prices, higher exploration expenses, lower production levels in Alaska, and higher production taxes in Alaska.

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

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

International E&P

Net income from our international E&P operations increased 33 percent in 2006, compared with 2005, reflecting higher crude oil, natural gas, and natural gas liquids prices and production, as well as higher levels of LNG production from the Darwin LNG facility associated with the Bayu-Undan field in the Timor Sea. These increases were offset partially by increased exploration expenses and a $93 million after-tax impairment charge associated with assets in the Canadian Rockies Foothills area. In addition, the increases to net income were partially offset by the net negative impacts of tax law changes in the United Kingdom, Canada, China, Venezuela, and Algeria.

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.

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

Midstream

	2007	2006	2005
	Millions of Dollars		
Net Income*	**$ 453**	476	688
**Includes DCP Midstream-related net income:*	***$ 336***	*385*	*591*
	Dollars Per Barrel		
Average Sales Prices			
U.S. natural gas liquids*			
Consolidated	**$47.93**	40.22	36.68
Equity	**46.80**	39.45	35.52

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

	Thousands of Barrels Daily		
Operating Statistics			
Natural gas liquids extracted*	**211**	209	195
Natural gas liquids fractionated**	**173**	144	168

**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, LLC, as well as our other natural gas gathering and processing operations, and natural gas liquids fractionation and marketing businesses, primarily in the United States and Trinidad.

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.

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

In July 2005, ConocoPhillips increased its ownership interest in DCP Midstream to 50 percent from 30.3 percent.

R&M

	2007	2006	2005
	Millions of Dollars		
Net Income			
United States	**$4,615**	3,915	3,329
International	**1,308**	566	844
	$5,923	4,481	4,173
	Dollars Per Gallon		
U.S. Average Sales Prices*			
Gasoline			
Wholesale	**$ 2.27**	2.04	1.73
Retail	**2.42**	2.18	1.88
Distillates — wholesale	**2.29**	2.11	1.80

**Excludes excise taxes.*

	Thousands of Barrels Daily		
Operating Statistics			
Refining operations*			
United States			
Crude oil capacity**	**2,035**	2,208	2,180
Crude oil runs	**1,944**	2,025	1,996
Capacity utilization (percent)	**96%**	92	92
Refinery production	**2,146**	2,213	2,186
International			
Crude oil capacity**	**687**	651	428
Crude oil runs	**616**	591	424
Capacity utilization (percent)	**90%**	91	99
Refinery production	**633**	618	439
Worldwide			
Crude oil capacity**	**2,722**	2,859	2,608
Crude oil runs	**2,560**	2,616	2,420
Capacity utilization (percent)	**94%**	92	93
Refinery production	**2,779**	2,831	2,625
Petroleum products sales volumes			
United States			
Gasoline	**1,244**	1,336	1,374
Distillates	**872**	850	876
Other products	**432**	531	519
	2,548	2,717	2,769
International	**697**	759	482
	3,245	3,476	3,251

**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, 2006 and 2005 was 2,037,000, 2,208,000, and 2,182,000 barrels per day, respectively, for our domestic refineries, and 669,000, 693,000, and 428,000 barrels per day at year-end 2007, 2006 and 2005, 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 Asia Pacific.

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 $141 million deferred tax benefit related to tax legislation in Germany during the third quarter of 2007.

These increases were partially offset by the net impact of our contribution of assets to WRB Refining LLC (WRB), our downstream business venture with EnCana; foreign currency impacts; and lower marketing sales volumes due to asset sales. See the "Business Environment and Executive Overview" section for our view of the factors supporting industry refining and marketing margins.

We expect our average worldwide refinery crude oil utilization rate for 2008 to average in the mid-nineties.

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.

2006 vs. 2005
Net income from the R&M segment increased 7 percent in 2006, compared with 2005. The increase resulted primarily from:
- Higher U.S. refining and marketing margins and higher U.S. refining volumes.
- The recognition of a net benefit related to business interruption insurance.
- The inclusion of an $83 million charge for the cumulative effect of adopting Financial Accounting Standards Board (FASB) Interpretation No. 47, "Accounting for Conditional Asset Retirement Obligations — an interpretation of FASB Statement No. 143" (FIN 47) in the results for 2005.

The increase in net income was partially offset by impairments on assets held for sale recognized in 2006, as well as higher depreciation expense.

U.S. R&M
Net income from our U.S. R&M operations increased 18 percent in 2006, compared with 2005, primarily due to:
- Higher refining and marketing margins, and higher refining volumes.
- The recognition of a net $111 million business interruption insurance benefit.
- A $78 million charge for the cumulative effect of adopting FIN 47 in 2005.

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

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

International R&M
Net income from our international R&M operations decreased 33 percent in 2006, compared with 2005, due primarily to:
- The recognition of a $214 million after-tax impairment charge on certain assets held for sale.
- Lower refining margins.
- Preliminary engineering costs for certain refinery-related projects.

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

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

LUKOIL Investment

	Millions of Dollars		
	2007	2006	2005
Net Income	**$1,818**	1,425	714
Operating Statistics*			
Net crude oil production (thousands of barrels daily)	**401**	360	235
Net natural gas production (millions of cubic feet daily)	**256**	244	67
Net refinery crude oil processed (thousands of barrels daily)	**214**	179	122

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

This segment represents our investment in the ordinary shares of LUKOIL, an international, integrated oil and gas company headquartered in Russia, which we account for under the equity method. During 2005, we expended $2,160 million to purchase LUKOIL's ordinary shares, increasing our ownership interest to 16.1 percent. We expended another $2,715 million to increase our ownership interest in LUKOIL to 20 percent at December 31, 2006, based on 851 million issued shares. At December 31, 2007, our ownership interest was 20 percent based on issued shares. Our ownership interest based on estimated shares outstanding, used for equity-method accounting, was 20.6 percent at December 31, 2006 and 2007.

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.

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

In addition to our estimate of our equity share of LUKOIL's earnings, this segment reflects the amortization of the basis difference between our equity interest in the net assets of LUKOIL and the historical cost of our investment in LUKOIL, and also includes the costs associated with our employees seconded to LUKOIL.

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

Chemicals

	Millions of Dollars		
	2007	2006	2005
Net Income	**$359**	492	323

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.

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.

2006 vs. 2005
Net income from the Chemicals segment increased 52 percent during 2006, compared with 2005. Results for 2006 reflected improved olefins and polyolefins margins and volumes. The results for 2006 also included a hurricane-related business interruption insurance benefit of $20 million after-tax, as well as lower utility costs due to decreased natural gas prices.

Emerging Businesses

	Millions of Dollars		
	2007	2006	2005
Net Income (Loss)			
Power	**$ 53**	82	43
Other	**(61)**	(67)	(64)
	$ (8)	15	(21)

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 other items, such as carbon-to-liquids, technology solutions, and alternative energy and programs, such as advanced hydrocarbon processes, energy conversion technologies, new petroleum-based products, and renewable fuels.

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.

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

Corporate and Other

	Millions of Dollars		
	2007	2006	2005
Net Loss			
Net interest	**$ (820)**	(870)	(467)
Corporate general and administrative expenses	**(176)**	(133)	(183)
Discontinued operations	**—**	—	(23)
Acquisition-related costs	**(44)**	(98)	—
Other	**(229)**	(86)	(105)
	$(1,269)	(1,187)	(778)

2007 vs. 2006

Net interest consists of interest and financing expense, net of interest income and capitalized interest, as well as premiums incurred on the early retirement of debt. Net interest decreased 6 percent in 2007, primarily due to higher amounts of interest being capitalized and higher interest income. These decreases were partially offset by the net impact of the interest components of the Quality Bank settlements and 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.

The category "Other" includes certain foreign currency transaction gains and losses, and environmental costs associated with sites no longer in operation. Results from Other were primarily impacted by foreign currency losses in 2007.

2006 vs. 2005

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

Corporate general and administrative expenses decreased 27 percent in 2006, compared with 2005, primarily due to reduced benefit-related expenses.

Acquisition-related costs in 2006 included seismic relicensing and other transition costs associated with the Burlington Resources acquisition.

Results from Other improved during 2006, compared with 2005, primarily due to foreign currency transaction gains in 2006, versus losses in 2005, partially offset by certain tax items not directly attributable to the operating segments.

Capital Resources and Liquidity

Financial Indicators

	Millions of Dollars Except as Indicated		
	2007	2006	2005
Net cash provided by operating activities	**$24,550**	21,516	17,628
Notes payable and long-term debt within one year	**1,398**	4,043	1,758
Total debt	**21,687**	27,134	12,516
Minority interests	**1,173**	1,202	1,209
Common stockholders' equity	**88,983**	82,646	52,731
Percent of total debt to capital*	**19%**	24	19
Percent of floating-rate debt to total debt	**25**	41	9

**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 2007 we raised $3,572 million in proceeds from asset dispositions. During 2007, available cash was used to support our ongoing capital expenditures and investments program, repurchase shares of our common stock, repay debt, provide loan financing to certain related parties, pay dividends, and meet the funding requirements related to the business venture with EnCana. During 2007, cash and cash equivalents increased $639 million to $1,456 million.

In addition to cash flows from operating activities and proceeds from asset sales, we also rely on our cash balance, commercial paper and credit facility programs, and our shelf registration statements, to support our short- and long-term liquidity requirements. We anticipate these sources of liquidity will be adequate to meet our funding requirements in the near- and long-term, including our capital spending program, our share repurchase program, dividend payments, required debt payments, and the funding requirements related to the business venture with EnCana. For additional information about the EnCana transaction, see Note 16 — Joint Venture Acquisition Obligation, in the Notes to Consolidated Financial Statements.

Our cash flows from operating activities increased in each of the annual periods from 2005 through 2007. Favorable market conditions played a significant role in the upward trend of our cash flows from operating activities. In addition, cash flows in 2007 benefited from the full year inclusion of the operating activity of Burlington Resources, versus only nine months in 2006. Absent any unusual event during 2008, we expect market conditions will again be the most important factor affecting our 2008 operating cash flows.

Significant Sources of Capital

Operating Activities

During 2007, cash of $24,550 million was provided by operating activities, a 14 percent increase over cash from operations of $21,516 million in 2006. Contributing to the increase 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.

During 2006, cash flow from operations increased $3,888 million to $21,516 million. The improvement, compared with 2005, reflects higher worldwide crude oil prices and U.S.

refining margins, higher distributions from equity affiliates, and the impact of the Burlington Resources acquisition, partially offset by higher interest payments.

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 2007 and 2006, we benefited from favorable crude oil and natural gas prices, as well as refining margins. The sustainability of these prices and margins is driven by market conditions over which we have no control. Absent other mitigating factors, as these prices and margins fluctuate, we would expect a corresponding change in our operating cash flows.

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

After adjusting our production rates for the impact of the expropriation of our Venezuelan oil operations in June 2007, our BOE production has increased in each of the past three years. These increases were driven primarily by acquisitions, including our increased ownership interest in LUKOIL during 2005 and 2006, the acquisition of Burlington Resources in 2006 and the business venture with EnCana in 2007. Our adjusted 2007 production was approximately 2.25 million BOE per day, after reductions for the expropriation, our exit from Dubai and the sale of non-core assets. We expect 2008 annual production to be similar to the adjusted 2007 amount. Through 2012, we expect our annual production growth rate to average approximately 2 percent. These projections are tied to projects currently scheduled to begin production or ramp-up in those years and exclude our Canadian Syncrude mining operations.

To maintain or grow our production volumes, we must continue to add to our proved reserve base. Our reserve replacement over the three-year period ending December 31, 2007, was 186 percent. The purchase of reserves in place was a significant factor in replacing our reserves over the past three years, partially offset by the expropriation of our Venezuelan oil assets. Significant purchases during this three-year period included reserves added in 2007 related to the EnCana business venture, the 2006 acquisition of Burlington Resources and the 2005 re-entry into Libya, as well as proved reserves added through our investments in LUKOIL.

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

As discussed in Critical Accounting Estimates, engineering estimates of proved reserves are imprecise, and therefore, each year reserves may be revised upward or downward due to the impact of changes in oil and gas prices or as more technical data becomes available on the reservoirs. In 2007 and 2005, revisions increased our reserves, while in 2006, revisions decreased 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 experienced with 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. See the "Outlook" section for additional discussion concerning our operations in Venezuela.

Asset Sales

Proceeds from asset sales in 2007 were $3,572 million, compared with $545 million in 2006. The increase is mainly due to ongoing 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. Through December 31, 2007, this program had generated proceeds of approximately $3.8 billion since inception. In 2008, we expect to complete the disposition of our retail assets in the United States, Norway, Sweden and Denmark.

Commercial Paper and Credit Facilities

In September 2007, we replaced our $5 billion and $2.5 billion revolving credit facilities, with one $7.5 billion revolving credit facility, expiring in September 2012. This facility may be used as direct bank borrowings, as support for the ConocoPhillips $7.5 billion commercial paper program, as support for the ConocoPhillips Qatar Funding Ltd. $1.5 billion commercial paper program, or as support for issuances of letters of credit totaling up to $750 million. The facility is broadly syndicated among financial institutions and does not contain any material adverse change provisions or any covenants requiring maintenance of specified financial ratios or ratings. The credit agreement contains 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 $7.5 billion commercial paper program, a portion of which may be denominated in other currencies (limited to euro 3 billion equivalent). Commercial paper maturities are generally limited to 90 days. The ConocoPhillips Qatar Funding Ltd. $1.5 billion commercial paper program is used to fund commitments relating to the Qatargas 3 project. At December 31, 2007 and 2006, we had no outstanding borrowings under the credit facilities, but $41 million in letters of credit had been issued at both dates. Under both commercial paper programs, there was $725 million of commercial paper outstanding at December 31, 2007, compared with $2,931 million at December 31, 2006. Since we had $725 million of commercial paper outstanding and had issued $41 million of letters of credit, we had access to $6.7 billion in borrowing capacity under our revolving credit facility at December 31, 2007.

At December 31, 2007, Moody's Investor Service had a rating of "A1" on our senior long-term debt; and Standard and Poors' Rating Service and Fitch had ratings of "A." We do not have any ratings triggers on any of our corporate debt that would cause an automatic event of default in the event of a downgrade of our credit rating and thereby impact our access to liquidity. In the event that our credit rating deteriorated to a level that would prohibit us from accessing the commercial paper market, we would still be able to access funds under our $7.5 billion revolving credit facilities.

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.

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, 2007, we had outstanding $1,173 million of equity in less than wholly owned consolidated subsidiaries held by minority interest owners, including a minority interest of $508 million in Ashford Energy Capital S.A. The remaining minority interest amounts are primarily related to operating joint ventures we control. The largest of these, $648 million, was related to the Darwin LNG project located in northern Australia.

In December 2001, in order to raise funds for general corporate purposes, ConocoPhillips and Cold Spring Finance S.a.r.l. (Cold Spring) formed Ashford Energy Capital S.A. through the contribution of a $1 billion ConocoPhillips subsidiary promissory note and $500 million cash by Cold Spring. Through its initial $500 million investment, Cold Spring is entitled to a cumulative annual preferred return based on three-month LIBOR rates, plus 1.32 percent. The preferred return at December 31, 2007, was 6.55 percent. In 2008, and at each 10-year anniversary thereafter, Cold Spring may elect to remarket their investment in Ashford, and if unsuccessful, could require ConocoPhillips to provide a letter of credit in support of Cold Spring's investment, or in the event that such letter of credit is not provided, then cause the redemption of their investment in Ashford. Should ConocoPhillips' credit rating fall below investment grade on a redemption date, Ashford would require a letter of credit to support $475 million of the term loans, as of December 31, 2007, 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, 2007, Ashford held $2.0 billion of ConocoPhillips subsidiary notes and $29 million in investments unrelated to ConocoPhillips. We report Cold Spring's investment as a minority interest because it is not mandatorily redeemable and the entity does not have a specified liquidation date. Other than the obligation to make payment on the subsidiary notes described above, Cold Spring does not have recourse to our general credit.

Off-Balance Sheet Arrangements

As part of our normal ongoing business operations and consistent with normal industry practice, we enter into numerous agreements with other parties to pursue business opportunities, which share costs and apportion risks among the parties as governed by the agreements. At December 31, 2007, we were liable for certain contingent obligations under the following contractual arrangements:

- **Qatargas 3:** Qatargas 3 is an integrated project to produce and liquefy natural gas from Qatar's North field. We own a 30 percent interest in the project. The other participants in the project are affiliates of Qatar Petroleum (68.5 percent) and Mitsui & Co., Ltd. (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, excluding accrued interest. Upon completion certification, which is expected in 2010, all project loan facilities, including the ConocoPhillips loan facilities, will become non-recourse to the project participants. At December 31, 2007, Qatargas 3 had $2.4 billion outstanding under all the loan facilities, of which ConocoPhillips provided $690 million, and an additional $43 million of accrued interest.
- **Rockies Express Pipeline LLC:** In June 2006, we issued a guarantee for 24 percent of the $2.0 billion in credit facilities of Rockies Express Pipeline LLC (Rockies Express), which will be used to construct a natural gas pipeline across a portion of the United States. The maximum potential amount of future payments to third-party lenders under the guarantee is estimated to be $480 million, which could become payable if the credit facility is fully utilized and Rockies Express fails to meet its obligations under the credit agreement. At December 31, 2007, Rockies Express had $1,625 million outstanding under the credit facilities, with our 24 percent guarantee equaling $390 million. In addition, we have a 24 percent guarantee on $600 million of Floating Rate Notes due 2009 issued by Rockies Express in September 2007. It is anticipated that

construction completion will be achieved in 2009, and refinancing will take place at that time, making the debt non-recourse. For additional information, see Note 7 — Variable Interest Entities (VIEs), in the Notes to Consolidated Financial Statements.

- **Keystone Oil Pipeline:** In December 2007, we acquired a 50 percent equity interest in the Keystone Oil Pipeline (Keystone), a joint venture with TransCanada Corporation. Keystone plans to construct a crude oil pipeline originating in Alberta, with delivery points in Illinois and Oklahoma. In connection with certain planning and construction activities, agreements were put in place with third parties to guarantee the payments due under those agreements. Our maximum potential amount of future payments under those agreements are estimated to be $400 million, which could become payable if Keystone fails to meet its obligations under the agreements noted above and the obligation 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 that payments would be required. All but $15 million of the guarantees will terminate after construction is completed, currently estimated to be in 2010.

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

Capital Requirements

For information about our capital expenditures and investments, see the "Capital Spending" section.

Our debt balance at December 31, 2007, was $21.7 billion, a decrease of $5.4 billion during 2007, and our debt-to-capital ratio was 19 percent at year-end 2007. Our debt-to-capital ratio at the end of 2008 will depend on realized commodity prices and margins, the funding of our capital program, and the level of our dividends and share repurchases. Our current debt-to-capital target is 20 percent to 25 percent.

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

Also, in January 2007, we redeemed our $153 million 7.25% Notes due 2007 upon their maturity. In February 2007, we reduced our Floating Rate Five-Year Term Note due 2011 from $5 billion to $4 billion, with a subsequent reduction in July 2007 to $3 billion. In April 2007, we redeemed our $1 billion Floating Rate Notes due 2007 upon their maturity. In October 2007, we redeemed $300 million of ConocoPhillips Australia Funding Company's Floating Rate Notes due 2009 at par plus accrued interest.

In May 2007, Polar Tankers Inc., a wholly owned subsidiary, issued $645 million of 5.951% Notes due 2037. The notes are fully and unconditionally guaranteed by ConocoPhillips and ConocoPhillips Company.

In December 2007, we terminated interest rate swaps on $350 million of our 4.75% Notes due 2012. No interest rate swaps remain on any of our debt.

In January 2008, we repaid $1 billion of our Floating Rate Five-Year Term Note due 2011, reducing the balance outstanding to $2 billion. In February 2008, we gave notice to redeem in March 2008 our $300 million 7.125% Debentures due 2028 at 102.7 percent, 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 ten-year period, beginning in 2007, to the upstream business venture, FCCL Oil Sands Partnership, 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 $593 million is short-term and is included in the "Accounts payable — related parties" line on our consolidated balance sheet. The principal portion of these payments, which totaled $425 million in 2007, is presented on our consolidated statement of cash flows as an other financing activity. Interest accrues at a fixed annual rate of 5.3 percent on the unpaid principal balance. Fifty percent of the quarterly interest payment is reflected as an additional capital contribution and is 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. During 2007, we repurchased 89.5 million shares of our common stock at a cost of $7.0 billion, including 177,110 shares at a cost of $14 million from a consolidated Burlington Resources grantor trust. We anticipate first-quarter 2008 share repurchases to be $2 billion to $3 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, 2007, we had provided $690 million in loan financing, and an additional $43 million of accrued interest. See the "Off-Balance Sheet Arrangements" section for additional information on Qatargas 3.

In 2004, we finalized our transaction with Freeport LNG Development, L.P. (Freeport LNG) to participate in a proposed LNG receiving terminal in Quintana, Texas. Construction began in early 2005. We do not have an ownership interest in the facility, but we do have a 50 percent interest in the general partnership managing the venture, along with contractual rights to regasification capacity of the terminal. We entered into a credit agreement with Freeport LNG to provide loan financing of approximately $631 million, excluding accrued interest, for the construction of the facility. Through December 31, 2007, we had provided $594 million in loan financing, and an additional $87 million of accrued interest.

In the fall of 2004, ConocoPhillips and LUKOIL agreed to the expansion of the Varandey terminal as part of our investment in the OOO Naryanmarneftegaz (NMNG) joint venture. We have an obligation to provide loan financing to Varandey

Terminal Company for 30 percent of the costs of the terminal expansion, but we will have no governance or ownership interest in the terminal. We estimate our total loan obligation for the terminal expansion to be approximately $416 million at current exchange rates, excluding interest to be accrued during construction. This amount will be adjusted as the project's cost estimate and schedule are updated and the ruble exchange rate fluctuates. Through December 31, 2007, we had provided $331 million in loan financing, and an additional $32 million of accrued interest.

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

In February 2008, we announced a quarterly dividend of 47 cents per share, representing a 15 percent increase over the previous quarter's dividend of 41 cents per share. The dividend is payable March 3, 2008, to stockholders of record at the close of business February 25, 2008.

Contractual Obligations

The following table summarizes our aggregate contractual fixed and variable obligations as of December 31, 2007:

	Millions of Dollars				
		Payments Due by Period			
	Total	Up to 1 Year	Year 2–3	Year 4–5	After 5 Years
Debt obligations[a]	$ 21,633	1,368	2,796	7,243	10,226
Capital lease obligations	54	30	7	—	17
Total debt	21,687	1,398	2,803	7,243	10,243
Interest on debt and other obligations	15,439	1,429	2,608	1,949	9,453
Operating lease obligations	3,308	732	1,032	737	807
Purchase obligations[b]	125,507	49,929	11,864	8,665	55,049
Joint venture acquisition obligation[c]	6,887	593	1,285	1,427	3,582
Other long-term liabilities[d]					
Asset retirement obligations	6,613	253	555	481	5,324
Accrued environmental costs	1,089	187	319	114	469
Unrecognized tax benefits[e]	144	144	[e]	[e]	[e]
Total	$180,674	54,665	20,466	20,616	84,927

(a) Includes $688 million of net unamortized premiums and discounts. See Note 15 — Debt, in the Notes to Consolidated Financial Statements, for additional information.

(b) Represents any agreement to purchase goods or services that is enforceable and legally binding and that specifies all significant terms. The majority of the purchase obligations are market-based contracts. Includes: (1) our commercial activities of $74,446 million, of which $31,834 million are primarily related to the supply of crude oil to our refineries and the optimization of the supply chain, $10,530 million primarily related to the supply of unfractionated natural gas liquids (NGL) to fractionators, optimization of NGL assets, and for resale to customers, $9,575 million on futures, $8,933 million primarily related to natural gas for resale customers, $7,354 million related to transportation, $4,984 million related to product purchases, $943 million related to power trades, and $293 million related to the purchase side of exchange agreements; (2) $45,744 million of purchase commitments for products, mostly natural gas and NGL, from CPChem over the remaining term of 92 years; and (3) purchase commitments for jointly owned fields and facilities where we are the operator, of which some of the obligations will be reimbursed by our co-venturers in these properties. Does not include: (1) purchase commitments for jointly owned fields and facilities where we are not the operator; and (2) an agreement to purchase up to 165,000 barrels per day of Venezuelan Merey, or equivalent, crude oil for a market price over a remaining 12-year term if a variety of conditions are met.

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

(d) Does not include: Pensions — for the 2008 through 2012 time period, we expect to contribute an average of $335 million per year to our qualified and non-qualified pension and postretirement medical plans in the United States and an average of $200 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 $460 million for 2008 and then approximately $300 million per year for the remaining four years. Our required minimum funding in 2008 is expected to be $110 million in the United States and $120 million outside the United States.

(e) Does not include unrecognized tax benefit of $999 million because the ultimate disposition and timing of any payments to be made with regard to such amounts is 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			
	2008 Budget	**2007**	2006	2005
E&P				
United States — Alaska	$ 1,007	**666**	820	746
United States — Lower 48	3,259	**3,122**	2,008	891
International	6,787	**6,147**	6,685	5,047
	11,053	**9,935**	9,513	6,684
Midstream	6	**5**	4	839
R&M				
United States	2,060	**1,146**	1,597	1,537
International	741	**240**	1,419	201
	2,801	**1,386**	3,016	1,738
LUKOIL Investment	—	**—**	2,715	2,160
Chemicals	—	**—**	—	—
Emerging Businesses	226	**257**	83	5
Corporate and Other	238	**208**	265	194
	$14,324	**11,791**	15,596	11,620
United States	$ 6,435	**5,225**	4,735	4,207
International	7,889	**6,566**	10,861	7,413
	$14,324	**11,791**	15,596	11,620

Our capital spending for the three-year period ending December 31, 2007, totaled $39.0 billion. During the three-year period, 67 percent of total spending went to our E&P segment. In addition to our capital expenditures and investments spending during 2007 and 2006, we also provided loans of approximately $700 million and $800 million, respectively, to certain related parties.

Our capital expenditures and investments budget for 2008 is $14.3 billion. Included in this amount is approximately $700 million in capitalized interest. We plan to direct 77 percent of the capital expenditures and investments budget to E&P and 20 percent to R&M. With the addition of loans to certain affiliated companies and principal contributions related to funding our portion of the EnCana transaction, our total capital program for 2008 is approximately $15.3 billion. See the "Capital Requirements" section, as well as Note 10 — Investments, Loans and Long-Term Receivables and Note 16 — Joint Venture Acquisition Obligation, in the Notes to Consolidated Financial Statements, for additional information.

E&P

Capital spending for E&P during the three-year period ending December 31, 2007, totaled $26.1 billion. The expenditures over this period supported key exploration and development projects including:

- Development drilling in the Greater Kuparuk Area, including West Sak; the Greater Prudhoe Bay Area; the Alpine field, including satellite field prospects; exploratory drilling; and the acquisition of acreage in Alaska.

- Oil and natural gas developments in the Lower 48 states, including New Mexico, Texas, Louisiana, Oklahoma, Montana, North Dakota and Colorado.
- The Magnolia development, Ursa and K-2 fields in the deepwater Gulf of Mexico.
- The acquisition of limited-term, fixed-volume overriding royalty interests in Utah and the San Juan Basin related to our natural gas production.
- Investment in the West2East Pipeline LLC (West2East), a company holding a 100 percent interest in Rockies Express Pipeline LLC (Rockies Express).
- Expansion of the Syncrude oil sands project, the development of the Surmont heavy-oil project, capital expenditures related to the EnCana upstream business venture, and development of conventional oil and gas reserves, all in Canada.
- Development of the Corocoro field offshore Venezuela (see Note 13 — Impairments, in the Notes to Consolidated Financial Statements, for additional information).
- The Ekofisk Area growth project and Alvheim project in the Norwegian North Sea.
- The Statfjord Late-Life project straddling the offshore boundary between Norway and the United Kingdom.
- The Britannia satellite and Clair developments in the U.K. North Sea and Atlantic Margin, respectively.
- An integrated project to produce and liquefy natural gas from Qatar's North field.
- Investments in three fields in Algeria.
- 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 on deepwater leases.
- The Kashagan field and satellite prospects in the Caspian Sea, offshore Kazakhstan.
- The acquisition of an interest in OOO Naryanmarneftegaz (NMNG), a joint venture with LUKOIL, and development of the Yuzhno Khylchuyu (YK) field.
- The Bayu-Undan gas recycle and liquefied natural gas development projects in the Timor Sea and northern Australia, respectively.
- The Belanak, Suban, Kerisi, Hiu and Belut projects in Indonesia.
- The Peng Lai 19-3 development in China's Bohai Bay and additional Bohai Bay appraisal and adjacent field prospects.
- Expenditures to develop the Su Tu Vang field and continued in-field development of the Rang Dong field in Vietnam.

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

2008 Capital Expenditures and Investments Budget

E&P's 2008 capital expenditures and investments budget is $11.1 billion, 11 percent higher than actual expenditures in 2007. Thirty-nine percent of E&P's 2008 capital expenditures and investments budget is planned for the United States.

Capital spending for our Alaskan operations is expected to fund Prudhoe Bay, Greater Kuparuk and western North Slope operations, including the Alpine satellite fields, as well as exploration activities. In addition, we anticipate further development spending in our Cook Inlet Area. As a result of increased production taxes enacted by the state of Alaska in the fourth quarter of 2007, we anticipate our 2008 capital expenditures will be less than originally planned, mainly related to reduced project funding on the North Slope of Alaska.

In the Lower 48, capital expenditures will focus primarily on developing natural gas reserves within core areas, including the San Juan Basin of New Mexico and Colorado; the Lobo Trend of south Texas; the Bossier and Cotton Valley Trends of east Texas and north Louisiana; the Barnett Shale Trend of north Texas; the Anadarko Basin of western Oklahoma; and the Piceance Basin in northwest Colorado. We also plan to pursue oil development in the Williston Basin of Montana and North Dakota, as well as oil and gas developments in southern Louisiana and the Permian Basin of West Texas. Offshore capital will be focused mainly on the Ursa development in the Gulf of Mexico. In addition, investments will be made in West2East for Rockies Express.

E&P is directing $6.8 billion of its 2008 capital expenditures and investments budget to international projects. Funds in 2008 will be directed to developing major long-term projects, including the Kashagan project in the Caspian Sea and the YK field in northern Russia, through the NMNG joint venture with LUKOIL; the J-Block fields, the Britannia satellites and the Ekofisk Area in the North Sea; the Bohai Bay project in China; heavy-oil projects in Canada and western Canada natural gas projects; offshore Block B and onshore South Sumatra in Indonesia; fields offshore Malaysia and Vietnam; the Qatargas 3 LNG project in Qatar; and the Waha concessions in Libya.

Proved Undeveloped Reserves

The net addition of proved undeveloped reserves accounted for 77 percent, 37 percent and 44 percent of our total net additions in 2007, 2006 and 2005, respectively. During these years, we converted, on average, 16 percent per year of our proved undeveloped reserves to proved developed reserves. Of our 2,921 million total BOE proved undeveloped reserves at December 31, 2007, we estimated that the average annual conversion rate for these reserves for the three-year period ending 2010 will be approximately 18 percent.

Costs incurred for the years ended December 31, 2007, 2006 and 2005, relating to the development of proved undeveloped oil and gas reserves were $6.4 billion, $6.4 billion, and $3.4 billion, respectively. Estimated future development costs relating to the development of proved undeveloped reserves for the years 2008 through 2010 are projected to be $4.5 billion, $3.6 billion, and $2.6 billion, respectively.

Approximately 78 percent of our proved undeveloped reserves at year-end 2007 were associated with 10 major development areas and our investment in LUKOIL. Eight of the major development areas are currently producing and are expected to have proved reserves convert from undeveloped to developed over time as development activities continue and/or production facilities are expanded or upgraded, and include:

- The Ekofisk field in the North Sea.
- The Peng Lai 19-3 field in China.

- Fields in the United States and Canada.
- EnCana business venture projects — Christina Lake and Foster Creek.
- 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.

Midstream
Capital spending for Midstream during the three-year period ending December 31, 2007, was primarily related to increasing our ownership interest in DCP Midstream in 2005 from 30.3 percent to 50 percent.

R&M
Capital spending for R&M during the three-year period ending December 31, 2007, 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. In addition, in December 2007, we invested funds to acquire a 50 percent equity interest in the Keystone Oil Pipeline (Keystone), a joint venture to construct a crude oil pipeline from Hardisty, Alberta to U.S. Midwest markets in Illinois and Oklahoma. During this three-year period, R&M capital spending was $6.1 billion, representing 16 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.
- A new ultra-low-sulfur diesel hydrotreater at the Sweeny refinery.
- Revamp of an existing hydrotreater for ultra-low-sulfur diesel and a new hydrogen plant at the Wood River refinery.
- Expansion of existing hydrotreaters for both low-sulfur gasoline and ultra-low-sulfur diesel, with the addition of a new hydrogen plant at the Bayway refinery.
- A new hydrotreater for ultra-low-sulfur diesel and a hydrogen plant at the Ponca City refinery.
- Revamps of existing hydrotreaters for ultra-low-sulfur diesel at the Los Angeles, Trainer and Ferndale refineries.
- A new ultra-low-sulfur diesel hydrotreater and hydrogen plant at the Billings refinery.
- A fluid catalytic cracking gasoline hydrotreater at the Alliance refinery for production of low-sulfur gasoline.
- A sulfur removal technology unit at the Lake Charles refinery for the production of low-sulfur gasoline.
- A new ultra-low-sulfur diesel hydrotreater at the Rodeo facility of our San Francisco 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.
- U.S. programs aimed at air emission reductions.

Internationally, we continued to invest in our ongoing refining and marketing operations to upgrade and increase the profitability of our existing assets, including upgrading the distillate desulfurization capabilities at our Humber refinery in the United Kingdom.

2008 Capital Expenditures and Investments Budget
R&M's 2008 capital budget is $2.8 billion, a 102 percent increase from actual spending in 2007. Domestic spending in 2008 is expected to comprise 74 percent of the R&M budget.

We plan to direct about $1.6 billion of the R&M capital budget to domestic refining, primarily for projects related to sustaining and improving the existing business with a focus on reliability, energy efficiency, capital maintenance and regulatory compliance. Work continues at a number of refineries on projects to increase crude oil capacity, expand conversion capability and increase clean product yield. Our North American transportation and marketing businesses are expected to spend about $800 million, including investments in the Keystone project.

Outside North America, we plan to spend about $400 million, with a focus on projects related to reliability, safety and the environment, as well as an upgrade project at the Wilhelmshaven, Germany, refinery and the advancement of a full-conversion refinery project in Yanbu, Saudi Arabia.

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

Emerging Businesses
Capital spending for Emerging Businesses during the three-year period ending December 31, 2007, 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 (SCLP). SCLP provides steam and electric power to the Sweeny refinery complex with any excess power sold into the market. We account for this joint venture using the equity method of accounting.

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 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 are other companies in the petroleum exploration and production, refining, and crude oil and refined product marketing and transportation businesses. The most significant of these environmental laws and regulations include, among others, the:

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

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

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

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

For example, the 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.

Since 1997 when the Kyoto Protocol called for reductions of certain emissions that contribute to increases in atmospheric greenhouse gas concentrations, there have been a range of national, sub-national and international regulations proposed or implemented focusing on greenhouse gas reduction. These actual or proposed regulations do or will apply in countries where we have interests or may have interests in the future. Regulation in this field continues to evolve and while it is likely to be increasingly widespread and stringent, at this stage it is not possible to accurately estimate either a timetable for implementation or our future compliance costs. The overall long-term fiscal impact from this type of regulation is uncertain. Examples of legislation or precursors for possible regulation include:

- European Emissions Trading Scheme, the program through which many of the European Union member states are implementing the Kyoto Protocol.
- California's Assembly Bill 32, which requires the California Air Resources Board (CARB) to develop regulations and market mechanisms that will ultimately reduce California's greenhouse gas emissions by 25 percent by 2020.
- 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. ___, 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.

There is growing consensus that some form of regulation will be forthcoming at the federal level in the United States with respect to greenhouse gas emissions (including carbon dioxide) and such regulation could result in the creation of substantial additional costs in the form of taxes or required acquisition or trading of emission allowances. Additionally, with the continuing trend toward stricter standards, greater regulation and more extensive permitting requirements, our capital and operating environmental expenditures are likely to be substantial and may increase in the future. We may experience significant delays in obtaining all required environmental regulatory permits or other approvals that we need to operate or upgrade our existing facilities or construct new facilities. If there is a delay in obtaining any required environmental regulatory approvals or permits, the operation of our facilities may be interrupted or become subject to additional costs.

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. Future environmental expenditures associated with the remediation of MTBE-contaminated underground storage tank sites could be substantial.

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

We, from time to time, receive requests for information or notices of potential liability from the EPA and state environmental agencies alleging that we are a potentially responsible party under CERCLA or an equivalent state statute. On occasion, we also have been made a party to cost recovery litigation by those agencies or by private parties. These requests, notices and lawsuits assert potential liability for remediation costs at various sites that typically are not owned by us, but allegedly contain wastes attributable to our past operations. As of December 31, 2006, we reported we had been notified of potential liability under CERCLA and comparable state laws at 64 sites around the United States. At December 31, 2007, we had resolved five of these sites and had received nine new notices of potential liability, leaving 68 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 $1,025 million in 2007 and are expected to be about $1.1 billion in 2008 and 2009. Capitalized environmental costs were $785 million in 2007 and are expected to be about $1.2 billion and $1.1 billion in 2008 and 2009, respectively.

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

Many of these liabilities result from CERCLA, RCRA and similar state laws that require us to undertake certain investigative and remedial activities at sites where we conduct, or once conducted, operations or at sites where ConocoPhillips-generated waste was disposed. The accrual also includes a number of sites we identified that may require environmental remediation, but which are not currently the subject of CERCLA, RCRA or state enforcement activities. If applicable, we accrue receivables for probable insurance or other third-party recoveries. In the future, we may incur significant costs under both CERCLA and RCRA. Considerable uncertainty exists with respect to these costs, and under adverse changes in circumstances, potential liability may exceed amounts accrued as of December 31, 2007.

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, 2007, our balance sheet included total accrued environmental costs of $1,089 million, compared with $1,062 million at December 31, 2006. We expect to incur a substantial majority of these expenditures within the next 30 years.

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

Other

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

New Accounting Standards

In September 2006, the FASB issued SFAS No. 157, "Fair Value Measurements." This Statement defines fair value, establishes a framework for its measurement and expands disclosures about fair value measurements. We use fair value measurements to measure, among other items, purchased assets and investments, derivative contracts and financial guarantees. We also use them to assess impairment of properties, plants and equipment, intangible assets and goodwill. The Statement does not apply to share-based payment transactions and inventory pricing. In February 2008, the FASB issued a FASB Staff Position (FSP) on Statement No. 157 that permits a one-year delay of the effective date for all non-financial assets and non-financial liabilities, except those that are recognized or disclosed at fair value in the financial statements on a recurring basis (at least annually). We will adopt this Statement effective January 1, 2008, with the exceptions allowed under the FSP described above and do not expect any significant impact to our consolidated financial statements, other than additional disclosures.

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 an entity to choose to measure financial instruments and certain other items similar to financial instruments at fair value, with all subsequent changes in fair value for the financial instrument 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 will adopt this Statement effective January 1, 2008, and do not expect any significant impact to our consolidated financial statements.

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. This Statement applies prospectively to business combinations for which the acquisition date is on or after January 1, 2009. However, 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 the prior business combination accounting starting January 1, 2009. We are currently evaluating the changes provided in this Statement.

Also in December 2007, the FASB issued SFAS No. 160, "Noncontrolling Interests in Consolidated Financial Statements—an amendment of ARB No. 51," which changes the classification of non-controlling interests, sometimes called a minority interest, in the consolidated financial statements. Additionally, this Statement establishes a single method of accounting for changes in a parent company's ownership interest that do not result in deconsolidation and requires a parent company to recognize a gain or loss when a subsidiary is deconsolidated. 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. We are currently evaluating the impact on our consolidated financial statements.

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 2007, 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 $1,385 million and the accumulated impairment reserve was $429 million. The weighted average judgmental percentage probability of ultimate failure was approximately 65 percent and the weighted average amortization period was approximately 2.1 years. If that judgmental percentage were to be raised by 5 percent across all calculations, pretax leasehold impairment expense in 2008 would increase by approximately $29 million. The remaining $4,134 million of capitalized unproved property costs at year-end 2007 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 billion is concentrated in 10 major assets. Management expects less than $50 million to move to proved properties in 2008. Most of the $2 billion is associated with North America and Asia Pacific natural gas projects and North America oil-sands projects, on which we continue to work with co-venturers and regulatory agencies to develop.

Exploratory Costs

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

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

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

At year-end 2007, total suspended well costs were $589 million, compared with $537 million at year-end 2006. For additional information on suspended wells, including an aging analysis, see Note 11 — Properties, Plants and Equipment, in the Notes to Consolidated Financial Statements.

Proved Oil and Gas Reserves and Canadian Syncrude Reserves

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

Despite the inherent imprecision in these engineering estimates, accounting rules require disclosure of "proved" reserve estimates due to the importance of these estimates to better understand the perceived value and future cash flows of a company's E&P operations. There are several authoritative guidelines regarding the engineering criteria that must be met before estimated reserves can be designated as "proved." Our reservoir engineering organization has policies and procedures in place that are consistent with these authoritative guidelines. We have qualified and experienced internal engineering personnel who make these estimates for our E&P segment.

All of our proved crude oil, natural gas and natural gas liquids reserves held by consolidated companies have been estimated by ConocoPhillips. Our policy with respect to equity affiliates is either to estimate the proved reserve quantities ourselves (applicable to those situations where we have a substantial engineering presence), or to rely on estimates prepared by the equity affiliate, and perform a reasonableness review of those assessments. Of the proved reserves attributable to equity affiliates at year-end 2007, 38 percent was based on assessments of the available data performed by ConocoPhillips. The remaining 62 percent, reflecting our equity interest in LUKOIL, was based on estimates prepared by the equity affiliate. These equity-affiliate-prepared estimates are reviewed by ConocoPhillips and adjusted to comply with our internal reserves governance policies.

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

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 go up then our applicable reserve quantities would decline.

The judgmental estimation of proved reserves also is important to the income statement because the proved oil and gas reserve estimate for a field or the estimated in-place crude bitumen volume for an oil sand mining operation serves as the denominator in the unit-of-production calculation of depreciation, depletion and amortization of the capitalized costs for that asset. At year-end 2007, the net book value of productive E&P properties, plants and equipment subject to a unit-of-production calculation, including our Canadian Syncrude bitumen oil sand assets, was approximately $63 billion and the depreciation, depletion and amortization recorded on these assets in 2007 was approximately $6.9 billion. The estimated proved developed oil and gas reserves on these fields were 6.4 billion BOE at the beginning of 2007 and were 6.1 billion BOE at the end of 2007. The estimated proved reserves on the Canadian Syncrude assets were 243 million barrels at the beginning of 2007 and were 221 million barrels at the end of 2007. If the judgmental estimates of proved reserves used in the unit-of-production calculations had been lower by 5 percent across all calculations, pretax depreciation, depletion and amortization in 2007 would have been increased by an estimated $361 million. Impairments of producing oil and gas properties in 2007, 2006 and 2005 totaled $471 million, $215 million and $4 million, respectively. Of these write-downs, $76 million in 2007, $131 million in 2006 and $1 million in 2005 were due to downward revisions of proved reserves.

Impairment of Assets

Long-lived assets used in operations are assessed for impairment whenever changes in facts and circumstances indicate a possible significant deterioration in the future cash flows expected to be generated by an asset group. If, upon review, the sum of the undiscounted pretax cash flows is less than the carrying value of the asset group, the carrying value is written down to estimated fair value. Individual assets are grouped for impairment purposes based on a judgmental assessment of the lowest level for which there are identifiable cash flows that are largely independent of the cash flows of other groups of assets — generally on a field-by-field basis for exploration and production assets, at an entire complex level for downstream assets, or at a site level for retail stores. Because there usually is a lack of quoted market prices for long-lived assets, the fair value usually is based on the present values of expected future cash flows using discount rates commensurate with the risks involved in the asset group. The expected future cash flows used for impairment reviews and related fair value calculations are based on judgmental assessments of future production volumes, prices and costs, considering all available information at the date of review. See Note 13 — Impairments, in the Notes to Consolidated Financial Statements, for additional information.

Asset Retirement Obligations and Environmental Costs

Under various contracts, permits and regulations, we have material legal obligations to remove tangible equipment and restore the land or seabed at the end of operations at operational sites. Our largest asset removal obligations involve removal and disposal of offshore oil and gas platforms around the world, oil and gas production facilities and pipelines in Alaska, and asbestos abatement at refineries. The 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.

See Note 1 — Accounting Policies, Note 14 — Asset Retirement Obligations and Accrued Environmental Costs, and Note 18 — Contingencies and Commitments, in the Notes to Consolidated Financial Statements, for additional information.

Business Acquisitions
Purchase Price Allocation
Accounting for the acquisition of a business requires the allocation of the purchase price to the various assets and liabilities of the acquired business. For most assets and liabilities, purchase price allocation is accomplished by recording the asset or liability at its estimated fair value. The most difficult estimations of individual fair values are those involving properties, plants and equipment and identifiable intangible assets. We use all available information to make these fair value determinations. 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, 2007, we had $731 million of intangible assets determined to have indefinite useful lives, thus they are not amortized. This judgmental assessment of an indefinite useful life has to be continuously evaluated in the future. If, due to changes in facts and circumstances, management determines that these intangible assets then have definite useful lives, amortization will have to commence at that time on a prospective basis. As long as these intangible assets are judged to have indefinite lives, they will be subject to periodic lower-of-cost-or-market tests that require management's judgment of the estimated fair value of these intangible assets. See Note 12 — Goodwill and Intangibles, in the Notes to Consolidated Financial Statements, for additional information.

At December 31, 2007, we had $29.3 billion of goodwill recorded in conjunction with past business combinations. Under the accounting rules for goodwill, this intangible asset is not amortized. Instead, goodwill is subject to annual reviews for impairment at a reporting unit level. The reporting unit or units used to evaluate and measure goodwill for impairment are determined primarily from the manner in which the business is managed. A reporting unit is an operating segment or a component that is one level below an operating segment. Prior to 2007, within our E&P and our R&M segments, we determined we had one and two reporting units, respectively, for purposes of assigning goodwill and testing for impairment. These were Worldwide Exploration and Production, Worldwide Refining and Worldwide Marketing. In December 2006, we announced a new business strategy for Worldwide Marketing to shift most of our marketing operations to a wholesale channel of trade and significantly increase the level of vertical integration between our refining and wholesale marketing operations. Because of this new business strategy, we plan to dispose of most of the retail outlets we operate or own. During 2007, the execution of this new business strategy was well under way and is expected to be fully in place by the end of 2008. In accordance with SFAS No. 142, "Goodwill and Other Intangible Assets" (SFAS No. 142), we have reassessed the reporting unit definitions within the R&M segment based on this new business strategy and have concluded that the refining and marketing components within the R&M segment now are economically similar enough to be aggregated into one reporting unit, Worldwide Refining and Marketing, beginning in 2007. No goodwill impairment would have been required in 2007 had we retained Worldwide Marketing as a separate reporting unit.

If we later reorganize our businesses or management structure so that the components within our two reporting units are no longer economically similar, the reporting units would be revised and goodwill would be re-assigned using a relative fair value approach in accordance with SFAS No. 142. Goodwill impairment testing at a lower reporting unit level could result in the recognition of impairment that would not otherwise be recognized at the current higher level of aggregation. In addition, the sale or disposition of a portion of these two reporting units will be allocated a portion of the reporting unit's goodwill, based on relative fair values, which will adjust the amount of gain or loss on the sale or disposition. When assessing the need for impairments on those sales and disposals, we take into consideration the anticipated allocation of goodwill and provisionally provide for its expected impairment upon final sale or disposal.

Because quoted market prices for our reporting units are not available, management must apply judgment in determining the estimated fair value of these reporting units for purposes of performing the periodic goodwill impairment test. Management uses all available information to make these fair value determinations, including the present values of expected future cash flows using discount rates commensurate with the risks involved in the assets and observed market multiples of operating cash flows and net income. In addition, if the estimated fair value of a reporting unit is less than the book value (including the goodwill), further judgment must be applied in determining the fair values of individual assets and liabilities for purposes of the hypothetical purchase price allocation. Again, management must use all available information to make these fair value determinations. At year-end 2007, the estimated fair values of our Worldwide Exploration and Production and Worldwide Refining and Marketing reporting units ranged from between 44 percent to 65 percent higher than recorded net book values (including goodwill) of the reporting units. However, a lower fair value estimate in the future for any of these reporting units could result in an impairment.

Projected Benefit Obligations

Determination of the projected benefit obligations for our defined benefit pension and postretirement plans are important to the recorded amounts for such obligations on the balance sheet and to the amount of benefit expense in the income statement. This also impacts the required company contributions into the plans. The actuarial determination of projected benefit obligations and company contribution requirements involves judgment about uncertain future events, including estimated retirement dates, salary levels at retirement, mortality rates, lump-sum election rates, rates of return on plan assets, future health care cost-trend rates, and rates of utilization of health care services by retirees. Due to the specialized nature of these calculations, we engage outside actuarial firms to assist in the determination of these projected benefit obligations. For Employee Retirement Income Security Act-qualified pension plans, the actuary exercises fiduciary care on behalf of plan participants in the determination of the judgmental assumptions used in determining required company contributions into plan assets. Due to differing objectives and requirements between financial accounting rules and the pension plan funding regulations promulgated by governmental agencies, the actuarial methods and assumptions for the two purposes differ in certain important respects. Ultimately, we will be required to fund all promised benefits under pension and postretirement benefit plans not funded by plan assets or investment returns, but the judgmental assumptions used in the actuarial calculations significantly affect periodic financial statements and funding patterns over time. Benefit expense is particularly sensitive to the discount rate and return on plan assets assumptions. A 1 percent decrease in the discount rate would increase annual benefit expense by $100 million, while a 1 percent decrease in the return on plan assets assumption would increase annual benefit expense by $55 million. In determining the discount rate, we use yields on high-quality fixed income investments (including among other things, Moody's Aa corporate bond yields) with adjustments as needed to match the estimated benefit cash flows of our plans.

Outlook

Alaska

In late 2007, we submitted a proposal to the governor of Alaska to advance the development of the Alaska Natural Gas Pipeline Project. The proposed pipeline would transport approximately 4 billion cubic feet per day of natural gas from the Alaska North Slope to markets in Canada and the United States. We have a 36.1 percent non-operator interest in the Greater Prudhoe Area fields that are expected to be a primary source of natural gas to be shipped in the proposed pipeline. Our proposal was submitted as an alternative to the process the Alaska Legislature established in its Alaska Gasline Inducement Act (AGIA). In our proposal, we stated our willingness to make significant investments, without state matching funds, to advance this project. In January 2008, we received a letter from the governor of Alaska stating our alternative does not give the state a reason to deviate from the AGIA process. We formally responded to the governor's letter on January 24, 2008. As a result of the lack of engagement by the state of Alaska on our proposal, we are reassessing how best to advance the Alaska natural gas pipeline project. During this reassessment, as an initial step we will continue planning and contracting efforts in preparation for route reconnaissance and environmental studies starting in June 2008. We expect to continue to testify before the Alaska Legislature and engage the Alaska public with our view of the best path forward to advance the gas pipeline project.

Venezuela

Negotiations continue between ConocoPhillips and Venezuelan authorities concerning appropriate compensation for the expropriation of the company's oil interests. We continue to preserve all our rights with respect to this situation, including our rights under the contracts we signed and under international and Venezuelan law. We continue to evaluate our options in realizing adequate compensation for the value of our oil investments and operations in Venezuela and 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.

Canada

On October 25, 2007, the Alberta provincial government publicly announced its intention to make a change to the royalty structure for Crown lands, effective January 1, 2009. Although the government's proposed change will require legislative and regulatory amendments to become effective and may be further modified before final adoption, there is a high likelihood there will be some form of change to the royalty structure in Alberta. While the precise impact of the proposed change is not determinable at this time, the adoption of the proposed royalty structure could result in a range of outcomes, including a negative adjustment to our Canadian reserve base. This change will impact both our conventional western Canada natural gas business and our oil sands operations.

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 projects, manufacturing or refining.
- Unexpected technological or commercial difficulties in manufacturing, refining, or transporting our products, including synthetic crude oil and chemicals products.
- Lack of, or disruptions in, adequate and reliable transportation for our crude oil, natural gas, natural gas liquids, LNG and refined products.
- Inability to timely obtain or maintain permits, including those necessary for construction of LNG terminals or regasification facilities, comply with government regulations, or make capital expenditures required to maintain compliance.
- Failure to complete definitive agreements and feasibility studies for, and to timely complete construction of, announced and future LNG and refinery projects and related facilities.
- Potential disruption or interruption of our operations due to accidents, extraordinary weather events, civil unrest, political events or terrorism.
- International monetary conditions and exchange controls.
- 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.
- Inability to obtain economical financing for projects, construction or modification of facilities and general corporate purposes.
- The operation and financing of our midstream and chemicals joint ventures.
- The factors generally described in the "Risk Factors" section included in "Items 1 and 2 — Business and Properties" in our 2007 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 without approval from the Chief Executive Officer. The Authority Limitations document also authorizes the Chief Executive Officer to establish the maximum Value at Risk (VaR) limits for the company and compliance with these limits is monitored daily. The Chief Financial Officer monitors risks resulting from foreign currency exchange rates and interest rates, while the Senior Vice President of Commercial monitors commodity price risk. Both report to the Chief Executive Officer. The Commercial organization manages our commercial marketing, optimizes our commodity flows and positions, monitors related risks of our upstream and downstream businesses, and selectively takes price risk to add value.

Commodity Price Risk

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

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

- Balance physical systems. In addition to cash settlement prior to contract expiration, exchange traded futures contracts also may be settled by physical delivery of the commodity, providing another source of supply to meet our refinery requirements or marketing demand.
- Meet customer needs. Consistent with our policy to generally remain exposed to market prices, we use swap contracts to convert fixed-price sales contracts, which are often requested by natural gas and refined product consumers, to a floating market price.
- Manage the risk to our cash flows from price exposures on specific crude oil, natural gas, refined product and electric power transactions.
- Enable us to use the market knowledge gained from these activities to do a limited amount of trading not directly related to our physical business. For the years ended December 31, 2007 and 2006, 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, 2007, 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, 2007 and 2006, was immaterial to our net income and cash flows. The VaR for instruments held for purposes other than trading at December 31, 2007 and 2006, 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 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**	
Year-End 2006				
2007	$ 557	7.43%	$ 1,000	5.37%
2008	32	6.96	—	—
2009	307	6.43	1,250	5.47
2010	1,433	8.85	—	—
2011	3,175	6.74	7,944	5.53
Remaining years	9,983	6.57	691	4.29
Total	$15,487		$10,885	
Fair value	$16,356		$10,885	

At the beginning of 2007, we held interest rate swaps that converted $350 million of debt from fixed to floating rate. Under SFAS No. 133, these swaps were designated as hedging the exposure to changes in the fair value of $350 million of 4.75% Notes due 2012. This hedge was terminated in December 2007, when we sold our positions in the swaps for approximately $3 million.

The following table presents 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 2007 effective yield rate of 4.9 percent, 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 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, 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, 2007 and 2006, 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, 2007 or 2006, exchange rates. The notional and fair market values of these positions at December 31, 2007 and 2006, were as follows:

	In Millions				
Foreign Currency Swaps	Notional*			Fair Market Value**	
		2007	2006	**2007**	2006
Sell U.S. dollar, buy euro	USD	**744**	242	**$ 3**	5
Sell U.S. dollar, buy British pound	USD	**1,049**	647	**(16)**	20
Sell U.S. dollar, buy Canadian dollar	USD	**1,195**	1,367	**13**	(19)
Sell U.S. dollar, buy Czech koruna	USD	**—**	7	**—**	—
Sell U.S. dollar, buy Danish krone	USD	**20**	17	**—**	—
Sell U.S. dollar, buy Norwegian kroner	USD	**779**	1,145	**15**	15
Sell U.S. dollar, buy Swedish krona	USD	**11**	108	**—**	—
Sell U.S. dollar, buy Slovakia koruna	USD	**—**	2	**—**	—
Sell U.S. dollar, buy Hungary forint	USD	**—**	4	**—**	—
Sell euro, buy Norwegian kroner	EUR	**—**	10	**—**	—
Sell euro, buy Canadian dollar	EUR	**58**	—	**—**	—
Buy euro, sell British pound	EUR	**1**	125	**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 19 — Financial Instruments and Derivative Contracts, in the Notes to Consolidated Financial Statements.

Selected Financial Data

	Millions of Dollars Except Per Share Amounts				
	2007	2006	2005	2004	2003
Sales and other operating revenues	**$187,437**	183,650	179,442	135,076	104,246
Income from continuing operations	**11,891**	15,550	13,640	8,107	4,593
Per common share					
Basic	**7.32**	9.80	9.79	5.87	3.37
Diluted	**7.22**	9.66	9.63	5.79	3.35
Net income	**11,891**	15,550	13,529	8,129	4,735
Per common share					
Basic	**7.32**	9.80	9.71	5.88	3.48
Diluted	**7.22**	9.66	9.55	5.80	3.45
Total assets	**177,757**	164,781	106,999	92,861	82,455
Long-term debt	**20,289**	23,091	10,758	14,370	16,340
Joint venture acquisition obligation — related party	**6,294**	—	—	—	—
Mandatorily redeemable minority interests	—	—	—	—	141
Cash dividends declared per common share	**1.64**	1.44	1.18	.895	.815

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 2007 includes the impact of a $4,588 million before-tax ($4,512 million after-tax) non-cash impairment related to the expropriation of our oil interests in Venezuela. For additional information, see the "Expropriated Assets" section of Note 13 — 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 5 — 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 the amounts included in the table above.

Selected Quarterly Financial Data*

	Millions of Dollars				Per Share of Common Stock			
					Income Before Cumulative Effect of Changes in Accounting Principles		Net Income	
	Sales and Other Operating Revenues**	Income from Continuing Operations Before Income Taxes	Income Before Cumulative Effect of Changes in Accounting Principles	Net Income	Basic	Diluted	Basic	Diluted
2007								
First	**$41,320**	**6,066**	**3,546**	**3,546**	**2.15**	**2.12**	**2.15**	**2.12**
Second***	**47,370**	**3,518**	**301**	**301**	**.18**	**.18**	**.18**	**.18**
Third	**46,062**	**6,364**	**3,673**	**3,673**	**2.26**	**2.23**	**2.26**	**2.23**
Fourth	**52,685**	**7,324**	**4,371**	**4,371**	**2.75**	**2.71**	**2.75**	**2.71**
2006								
First	$46,906	5,797	3,291	3,291	2.38	2.34	2.38	2.34
Second	47,149	8,682	5,186	5,186	3.13	3.09	3.13	3.09
Third	48,076	7,937	3,876	3,876	2.35	2.31	2.35	2.31
Fourth	41,519	5,917	3,197	3,197	1.94	1.91	1.94	1.91

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

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

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

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

Closing Stock Price at December 31, 2007	$88.30
Closing Stock Price at January 31, 2008	$80.11
Number of Stockholders of Record at January 31, 2008*	64,486

**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, 2007. 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, 2007.

Ernst & Young LLP has issued an audit report on the company's internal control over financial reporting as of December 31, 2007.

James J. Mulva
Chairman, President and
Chief Executive Officer

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

February 21, 2008

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, 2007 and 2006, and the related consolidated statements of income, changes in common stockholders' equity, and cash flows for each of the three years in the period ended December 31, 2007. 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, 2007 and 2006, and the consolidated results of its operations and its cash flows for each of the three years in the period ended December 31, 2007, 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)," and in 2005 ConocoPhillips adopted Financial Accounting Standards Board Interpretation No. 47, "Accounting for Conditional Asset Retirement Obligations — an interpretation of FASB Statement No. 143."

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), ConocoPhillips' internal control over financial reporting as of December 31, 2007, based on criteria established in *Internal Control — Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission and our report dated February 21, 2008 expressed an unqualified opinion thereon.

Ernst + Young LLP

Houston, Texas
February 21, 2008

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, 2007, 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, 2007, based on the COSO criteria.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the 2007 consolidated financial statements of ConocoPhillips and our report dated February 21, 2008 expressed an unqualified opinion thereon.

Ernst + Young LLP

Houston, Texas
February 21, 2008

Consolidated Income Statement

Years Ended December 31	Millions of Dollars		
	2007	2006	2005
Revenues and Other Income			
Sales and other operating revenues*	$ **187,437**	183,650	179,442
Equity in earnings of affiliates	**5,087**	4,188	3,457
Other income	**1,971**	685	465
Total Revenues and Other Income	**194,495**	188,523	183,364
Costs and Expenses			
Purchased crude oil, natural gas and products	**123,429**	118,899	124,925
Production and operating expenses	**10,683**	10,413	8,562
Selling, general and administrative expenses	**2,306**	2,476	2,247
Exploration expenses	**1,007**	834	661
Depreciation, depletion and amortization	**8,298**	7,284	4,253
Impairment — expropriated assets	**4,588**	—	—
Impairments	**442**	683	42
Taxes other than income taxes*	**18,990**	18,187	18,356
Accretion on discounted liabilities	**341**	281	193
Interest and debt expense	**1,253**	1,087	497
Foreign currency transaction (gains) losses	**(201)**	(30)	48
Minority interests	**87**	76	33
Total Costs and Expenses	**171,223**	160,190	159,817
Income from continuing operations before income taxes	**23,272**	28,333	23,547
Provision for income taxes	**11,381**	12,783	9,907
Income From Continuing Operations	**11,891**	15,550	13,640
Discontinued operations	**—**	—	(23)
Income before cumulative effect of changes in accounting principles	**11,891**	15,550	13,617
Cumulative effect of changes in accounting principles	**—**	—	(88)
Net Income	$ **11,891**	15,550	13,529
Income (Loss) Per Share of Common Stock (*dollars*)			
Basic			
Continuing operations	$ **7.32**	9.80	9.79
Discontinued operations	**—**	—	(.02)
Before cumulative effect of changes in accounting principles	**7.32**	9.80	9.77
Cumulative effect of changes in accounting principles	**—**	—	(.06)
Net Income	$ **7.32**	9.80	9.71
Diluted			
Continuing operations	$ **7.22**	9.66	9.63
Discontinued operations	**—**	—	(.02)
Before cumulative effect of changes in accounting principles	**7.22**	9.66	9.61
Cumulative effect of changes in accounting principles	**—**	—	(.06)
Net Income	$ **7.22**	9.66	9.55
Average Common Shares Outstanding (*in thousands*)			
Basic	**1,623,994**	1,585,982	1,393,371
Diluted	**1,645,919**	1,609,530	1,417,028
**Includes excise taxes on petroleum products sales:*	*$ 15,937*	*16,072*	*17,037*

See Notes to Consolidated Financial Statements.

At December 31	Millions of Dollars	
	2007	2006
Assets		
Cash and cash equivalents	**$ 1,456**	817
Accounts and notes receivable (net of allowance of $58 million in 2007 and $45 million in 2006)	**14,687**	13,456
Accounts and notes receivable — related parties	**1,667**	650
Inventories	**4,223**	5,153
Prepaid expenses and other current assets	**2,702**	4,990
Total Current Assets	**24,735**	25,066
Investments and long-term receivables	**31,457**	19,595
Loans and advances — related parties	**1,871**	1,118
Net properties, plants and equipment	**89,003**	86,201
Goodwill	**29,336**	31,488
Intangibles	**896**	951
Other assets	**459**	362
Total Assets	**$ 177,757**	164,781
Liabilities		
Accounts payable	**$ 16,591**	14,163
Accounts payable — related parties	**1,270**	471
Notes payable and long-term debt due within one year	**1,398**	4,043
Accrued income and other taxes	**4,814**	4,407
Employee benefit obligations	**920**	895
Other accruals	**1,889**	2,452
Total Current Liabilities	**26,882**	26,431
Long-term debt	**20,289**	23,091
Asset retirement obligations and accrued environmental costs	**7,261**	5,619
Joint venture acquisition obligation — related party	**6,294**	—
Deferred income taxes	**21,018**	20,074
Employee benefit obligations	**3,191**	3,667
Other liabilities and deferred credits	**2,666**	2,051
Total Liabilities	**87,601**	80,933
Minority Interests	**1,173**	1,202
Common Stockholders' Equity		
Common stock (2,500,000,000 shares authorized at $.01 par value)		
Issued (2007 — 1,718,448,829 shares; 2006 — 1,705,502,609 shares)		
Par value	**17**	17
Capital in excess of par	**42,724**	41,926
Grantor trusts (at cost: 2007 — 42,411,331 shares; 2006 — 44,358,585 shares)	**(731)**	(766)
Treasury stock (at cost: 2007 — 104,607,149 shares; 2006 — 15,061,613 shares)	**(7,969)**	(964)
Accumulated other comprehensive income	**4,560**	1,289
Unearned employee compensation	**(128)**	(148)
Retained earnings	**50,510**	41,292
Total Common Stockholders' Equity	**88,983**	82,646
Total	**$ 177,757**	164,781

See Notes to Consolidated Financial Statements.

Consolidated Statement of Cash Flows

Years Ended December 31	Millions of Dollars		
	2007	2006	2005
Cash Flows From Operating Activities			
Net income	**$ 11,891**	15,550	13,529
Adjustments to reconcile net income to net cash provided by continuing operations			
Non-working capital adjustments			
Depreciation, depletion and amortization	**8,298**	7,284	4,253
Impairment — expropriated assets	**4,588**	—	—
Impairments	**442**	683	42
Dry hole costs and leasehold impairments	**463**	351	349
Accretion on discounted liabilities	**341**	281	193
Deferred taxes	**(157)**	263	1,101
Undistributed equity earnings	**(1,823)**	(945)	(1,774)
Gain on asset dispositions	**(1,348)**	(116)	(278)
Discontinued operations	**—**	—	23
Cumulative effect of changes in accounting principles	**—**	—	88
Other	**105**	(201)	(139)
Working capital adjustments*			
Decrease in aggregate balance of accounts receivable sold	**—**	—	(480)
Increase in other accounts and notes receivable	**(2,492)**	(906)	(2,665)
Decrease (increase) in inventories	**767**	(829)	(182)
Decrease (increase) in prepaid expenses and other current assets	**487**	(372)	(407)
Increase in accounts payable	**2,772**	657	3,156
Increase (decrease) in taxes and other accruals	**216**	(184)	824
Net cash provided by continuing operations	**24,550**	21,516	17,633
Net cash used in discontinued operations	**—**	—	(5)
Net Cash Provided by Operating Activities	**24,550**	21,516	17,628
Cash Flows From Investing Activities			
Acquisition of Burlington Resources Inc.**	**—**	(14,285)	—
Capital expenditures and investments, including dry hole costs**	**(11,791)**	(15,596)	(11,620)
Proceeds from asset dispositions	**3,572**	545	768
Long-term advances/loans — related parties	**(682)**	(780)	(275)
Collection of advances/loans — related parties	**89**	123	111
Other	**250**	—	—
Net cash used in continuing operations	**(8,562)**	(29,993)	(11,016)
Net Cash Used in Investing Activities	**(8,562)**	(29,993)	(11,016)
Cash Flows From Financing Activities			
Issuance of debt	**935**	17,314	452
Repayment of debt	**(6,454)**	(7,082)	(3,002)
Issuance of company common stock	**285**	220	402
Repurchase of company common stock	**(7,001)**	(925)	(1,924)
Dividends paid on company common stock	**(2,661)**	(2,277)	(1,639)
Other	**(444)**	(185)	27
Net cash provided by (used in) continuing operations	**(15,340)**	7,065	(5,684)
Net Cash Provided by (Used in) Financing Activities	**(15,340)**	7,065	(5,684)
Effect of Exchange Rate Changes on Cash and Cash Equivalents	**(9)**	15	(101)
Net Change in Cash and Cash Equivalents	**639**	(1,397)	827
Cash and cash equivalents at beginning of year	**817**	2,214	1,387
Cash and Cash Equivalents at End of Year	**$ 1,456**	817	2,214

**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							
	Issued	Held in Treasury	Held in Grantor Trusts	Par Value	Capital in Excess of Par	Treasury Stock	Grantor Trusts	Accumulated Other Comprehensive Income	Unearned Employee Compensation	Retained Earnings	Total
December 31, 2004	1,437,729,662	—	48,182,820	$14	26,047	—	(816)	1,592	(242)	16,128	42,723
Net income										13,529	13,529
Other comprehensive income (loss)											
Minimum pension liability adjustment								(56)			(56)
Foreign currency translation adjustments								(717)			(717)
Unrealized loss on securities								(6)			(6)
Hedging activities								1			1
Comprehensive income											12,751
Cash dividends paid on company common stock										(1,639)	(1,639)
Repurchase of company common stock		32,080,000				(1,924)					(1,924)
Distributed under incentive compensation and other benefit plans	18,131,678		(2,250,727)		707		38				745
Recognition of unearned compensation									75		75
December 31, 2005	1,455,861,340	32,080,000	45,932,093	14	26,754	(1,924)	(778)	814	(167)	28,018	52,731
Net income										15,550	15,550
Other comprehensive income											
Minimum pension liability adjustment								33			33
Foreign currency translation adjustments								1,013			1,013
Hedging activities								4			4
Comprehensive income											16,600
Initial application of SFAS No. 158								(575)			(575)
Cash dividends paid on company common stock										(2,277)	(2,277)
Burlington Resources acquisition	239,733,571	(32,080,000)	890,180	3	14,475	1,924	(53)				16,349
Repurchase of company common stock		15,061,613	(542,000)			(964)	32				(932)
Distributed under incentive compensation and other benefit plans	9,907,698		(1,921,688)		697		33				730
Recognition of unearned compensation									19		19
Other										1	1
December 31, 2006	1,705,502,609	15,061,613	44,358,585	17	41,926	(964)	(766)	1,289	(148)	41,292	82,646
Net income										**11,891**	**11,891**
Other comprehensive income (loss)											
Defined benefit pension plans:											
Net prior service cost								**63**			**63**
Net gain								**213**			**213**
Non-sponsored 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**

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, certain transportation assets and Canadian Syncrude mining operations are consolidated on a proportionate basis. Other securities and investments, excluding marketable securities, are generally carried at cost.

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

- **Use of Estimates** — The preparation of financial statements in conformity with accounting principles generally accepted in the United States requires management to make estimates and assumptions that affect the reported amounts of assets, liabilities, revenues and expenses, and the disclosures of contingent assets and liabilities. Actual results could differ from 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 non-recoverable through remaining production, are recognized as accounts receivable or accounts payable, as appropriate. Cumulative differences between volumes sold and entitlement volumes are generally not significant.

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

- **Shipping and Handling Costs** — Our Exploration and Production (E&P) segment includes shipping and handling costs in production and operating expenses 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 are recorded as permanent adjustments to the LIFO cost basis. LIFO is used to better match current inventory costs with current revenues and to meet tax-conformity requirements. Costs include both direct and indirect expenditures incurred in bringing an item or product to its existing condition and location, but not unusual/non-recurring costs or research and development costs. Materials, supplies and other miscellaneous inventories, 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. Recognition and classification of the gain or loss that results from recording and adjusting a derivative to fair value depends on the purpose for issuing or holding the derivative. Gains and losses from derivatives that are not accounted for as hedges under Statement of Financial Accounting Standards (SFAS) No. 133, "Accounting for Derivative Instruments and Hedging Activities," are recognized immediately in earnings. For derivative instruments that are designated and qualify as a fair value hedge, the gains or losses from adjusting the derivative to its fair value will be immediately recognized in earnings and, to the extent the hedge is effective, offset the concurrent recognition of changes in the fair value of the hedged item. Gains or losses from derivative instruments that are designated and qualify as a cash flow hedge will be recorded on the balance sheet in accumulated other comprehensive income until the hedged transaction is recognized in earnings; however, to the extent the change in the value of the derivative exceeds the change in the anticipated cash flows of the hedged transaction, the excess gains or losses will be recognized immediately in earnings.

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

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

Property Acquisition Costs — Oil and gas leasehold acquisition costs are capitalized and included in the balance sheet caption properties, plants and equipment. Leasehold impairment is recognized based on exploratory experience and management's judgment. Upon 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 we seek government or co-venturer approval of development plans or seek environmental permitting. Once all required approvals and permits have been obtained, the projects are moved into the development phase and the oil and gas reserves are designated as proved reserves.

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

See Note 11 — Properties, Plants and Equipment, for additional information on suspended wells.

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

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

- **Syncrude Mining Operations** — Capitalized costs, including support facilities, include 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, three reporting units had been determined prior to 2007: Worldwide Exploration and Production, Worldwide Refining and Worldwide Marketing. In 2007, the Refining unit and Marketing unit were combined into one unit, Worldwide Refining and Marketing. Because quoted market prices are not available for the company's reporting units, the fair value of the reporting units is determined based upon consideration of several factors, including the present values of expected future cash flows using discount rates commensurate with the risks involved in the operations and observed market multiples of operating cash flows and net income.

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

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

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

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

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

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

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

■ **Asset Retirement Obligations and Environmental Costs** — We record the fair value of legal obligations to retire and remove long-lived assets in the period in which the obligation is incurred (typically when the asset is installed at the production location). When the liability is initially recorded, we capitalize this cost by increasing the carrying amount of the related properties, plants and equipment. Over time the liability is increased for the change in its present value, and the capitalized cost in properties, plants and equipment is depreciated over the useful life of the related asset. See Note 14 — Asset Retirement Obligations and Accrued Environmental Costs, for additional information.

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

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

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

  Employee stock options granted prior to 2003 were accounted for under Accounting Principles Board (APB) Opinion No. 25, "Accounting for Stock Issued to Employees," and related Interpretations; however, by the end of 2005, all of these awards had vested. Because the exercise price of our employee stock options equaled the market price of the underlying stock on the date of grant, generally no compensation expense was recognized under APB Opinion No. 25. The following table displays 2005 pro forma information as if the provisions of SFAS No. 123 had been applied to all employee stock options granted:

	Millions of Dollars
Net income, as reported	$13,529
Add: Stock-based employee compensation expense included in reported net income, net of related tax effects	142
Deduct: Total stock-based employee compensation expense determined under fair-value based method for all awards, net of related tax effects	(144)
Pro forma net income	$13,527
Earnings per share:	
Basic — as reported	$ 9.71
Basic — pro forma	9.71
Diluted — as reported	9.55
Diluted — pro forma	9.55

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

  Effective January 1, 2006, we adopted SFAS No. 123 (revised 2004), "Share-Based Payment" (SFAS No. 123(R)), which requires us to recognize stock-based compensation expense for new awards over the shorter of: 1) the service period (i.e., the stated period of time required to earn the award); or 2) the period beginning at the start of the service period and ending when an employee first becomes eligible for retirement. This shortens the period over which we recognize expense for most of our stock-based awards granted to our employees who are already age 55 or older, but it has not had a material effect on our 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 Per Share of Common Stock** — Basic income per share of common stock is calculated based upon the daily weighted-average number of common shares outstanding during the year, including unallocated shares held by the stock savings feature of the ConocoPhillips Savings Plan. Also, this calculation includes fully vested stock and unit awards that have not been issued. Diluted income per share of common stock includes the above, plus unvested stock, unit or option awards granted under our compensation plans and vested but unexercised stock options, but only to the extent these instruments dilute net income per share. Treasury stock and shares held by the grantor trusts are excluded from the daily weighted-average number of common shares outstanding in both calculations.

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

Note 2 — Changes in Accounting Principles

In June 2006, the Financial Accounting Standards Board (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. See Note 24 — 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 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 all the periods prior to April 1, 2006.

	Millions of Dollars		
	Actual	Pro Forma	
	2007	2006	2005
Sales and other operating revenues	**$187,437**	176,993	154,692
Purchased crude oil, natural gas and products	**123,429**	112,242	100,175

For information on our December 31, 2005, adoption of FASB Interpretation No. 47, "Accounting for Conditional Asset Retirement Obligations — an interpretation of FASB Statement No. 143," and related disclosures, see Note 14 — Asset Retirement Obligations and Accrued Environmental Costs.

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 will adopt effective December 31, 2008. For information on the impact of the adoption of this new Statement, see Note 23 — Employee Benefit Plans.

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

In December 2004, the FASB issued SFAS No. 123 (revised 2004), "Share-Based Payment," (SFAS No. 123(R)), which superseded APB Opinion No. 25, "Accounting for Stock Issued to Employees," and replaced SFAS No. 123, "Accounting for Stock-Based Compensation," that we adopted effective January 1, 2003. SFAS No. 123(R) prescribes the accounting for a wide range of share-based compensation arrangements, including options, restricted-share plans, performance-based awards, share appreciation rights, and employee share purchase plans, and generally requires the fair value of share-based awards to be expensed. Our adoption of the provisions of this Statement on January 1, 2006, using the modified-prospective transition method, did not have a material impact on our financial statements. For more information on our adoption of SFAS No. 123(R) and its effect on net income, see Note 1 — Accounting Policies and the "Share-Based Compensation Plans" section in Note 23 — Employee Benefit Plans.

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

Note 3 — Common Stock Split

On April 7, 2005, our Board of Directors declared a 2-for-1 common stock split effected in the form of a 100 percent stock dividend, payable June 1, 2005, to stockholders of record as of May 16, 2005. The total number of authorized common shares and associated par value per share were unchanged by this action. Shares and per-share information in this report are on an after-split basis for all periods presented.

Note 4 — Discontinued Operations

During 2005, we sold the majority of the remaining assets that had been previously classified as discontinued operations and reclassified the remaining immaterial assets back into continuing operations.

Sales and other operating revenues and income (loss) from discontinued operations for 2005 were as follows:

	Millions of Dollars
Sales and other operating revenues from discontinued operations	$356
Discontinued operations before-tax	$ (26)
Income tax benefit	(3)
Discontinued operations	$ (23)

Note 5 — Acquisition of Burlington Resources Inc.

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

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

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

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

The 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 summarizes the final purchase price allocation of the fair value of the assets acquired and liabilities assumed as of March 31, 2006:

	Millions of Dollars
Cash and cash equivalents	$ 3,238
Accounts and notes receivable	1,432
Inventories	229
Prepaid expenses and other current assets	108
Investments and long-term receivables	268
Properties, plants and equipment	28,176
Goodwill	16,787
Intangibles	107
Other assets	46
Total assets	$50,391
Accounts payable	$ 1,487
Notes payable and long-term debt due within one year	1,009
Accrued income and other taxes	697
Employee benefit obligations — current	248
Other accruals	254
Long-term debt	3,330
Asset retirement obligations	730
Accrued environmental costs	174
Deferred income taxes	7,849
Employee benefit obligations	347
Other liabilities and deferred credits	397
Common stockholders' equity	33,869
Total liabilities and equity	$50,391

All of the goodwill was assigned to the Worldwide Exploration and Production reporting unit. Of the $16,787 million of goodwill, $7,953 million relates to net deferred tax liabilities arising from differences between the allocated financial bases and deductible tax bases of the acquired assets. None of the goodwill is deductible for tax purposes.

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

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

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

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

Note 6 — Restructuring

As a result of the acquisition of Burlington Resources, we implemented a restructuring program in March 2006 to capture the synergies of combining the two companies. Under this program, we recorded accruals totaling $230 million in 2006 for employee severance payments, site closings, incremental pension benefit costs associated with the work force reductions, and employee relocations. Approximately 600 positions were identified for elimination, most of which were in the United States.

Of the total accrual, $224 million was reflected in the Burlington Resources purchase price allocation as an assumed liability, and $6 million ($4 million after-tax) related to ConocoPhillips was reflected in selling, general and administrative expenses in 2006. Included in the total accruals of $230 million was $12 million related to pension benefits to be paid in conjunction with other retirement benefits over a number of future years. The following table summarizes activity related to the non-pension accrual.

	Millions of Dollars
Balance at January 1, 2006	$ —
Accruals	218
Benefit payments	(98)
Balance at December 31, 2006	120
Accruals	13
Benefit payments	**(68)**
Balance at December 31, 2007	**$ 65***

**Includes current liabilities of $40 million. All work force reductions are expected to be completed by March 2008. Some site closings and continuation of employee benefits are expected to extend beyond one year from December 31, 2007.*

Note 7 — Variable Interest Entities (VIEs)

In June 2006, ConocoPhillips acquired a 24 percent interest in West2East Pipeline LLC (West2East), a company holding a 100 percent interest in Rockies Express Pipeline LLC (Rockies Express). Rockies Express plans to construct a natural gas pipeline from Colorado to Ohio. West2East is a VIE because a third party other than ConocoPhillips and our partners holds a significant voting interest in the company until project completion. We currently participate in the management committee of West2East as a non-voting member. We are not the primary beneficiary of West2East, and we use the equity method of accounting for our investment. We issued a guarantee for 24 percent of the $2 billion in credit facilities of Rockies Express. In addition, we have a guarantee for 24 percent of $600 million of Floating Rate Notes due 2009 issued by Rockies Express in September 2007. At December 31, 2007, the book value of our investment in West2East was $101 million. See Note 17 — Guarantees, for additional information.

In June 2005, ConocoPhillips and OAO LUKOIL (LUKOIL) created the OOO Naryanmarneftegaz (NMNG) joint venture to develop resources in the Timan-Pechora province of Russia. The NMNG joint venture is a VIE because we and our related party, LUKOIL, have disproportionate interests. We have a 30 percent ownership interest with a 50 percent governance interest in the joint venture. We are not the primary beneficiary of the VIE and we use the equity method of accounting for this investment. At December 31, 2007, the book value of our investment in the venture was $1,662 million.

Production from the NMNG joint-venture fields is transported via pipeline to LUKOIL's existing terminal at Varandey Bay on the Barents Sea and then shipped via tanker to international markets. LUKOIL intends to complete an expansion of the terminal's oil-throughput capacity from 30,000 barrels per day to 240,000 barrels per day, with ConocoPhillips participating in the financing of the expansion. The terminal entity, Varandey Terminal Company, is a VIE because we and our related party, LUKOIL, have disproportionate interests. We have an obligation to fund, through loans, 30 percent of the terminal's costs, but we will have no governance or ownership interest in the terminal. We are not the primary beneficiary and account for our loan to Varandey Terminal Company as a financial asset. We estimate our total loan obligation for the terminal expansion to be approximately $416 million at current exchange rates, excluding interest to be accrued during construction. This amount will be adjusted as the project's cost estimate and schedule are updated and the ruble exchange rate fluctuates. Through December 31, 2007, we had provided $331 million in loan financing, and an additional $32 million of accrued interest.

In 2004, we finalized a transaction with Freeport LNG Development, L.P. (Freeport LNG) to participate in a liquefied natural gas (LNG) receiving terminal in Quintana, Texas. We have no ownership in Freeport LNG; however, we obtained a 50 percent interest in Freeport LNG GP, Inc., which serves as the general partner managing the venture. We entered into a credit agreement with Freeport LNG, whereby we will provide loan financing of approximately $631 million, excluding accrued interest for the construction of the terminal. Through December 31, 2007, we had provided $594 million in financing, and an additional $87 million of accrued interest. Freeport LNG is a VIE, and we are not the primary beneficiary. We account for our loan to Freeport LNG as a financial asset.

In 2003, we entered into two 20-year agreements establishing separate guarantee facilities of $50 million each for two LNG ships then under construction. Subject to the terms of the facilities, we will be required to make payments should the charter revenue generated by the respective ships fall below a certain specified minimum threshold, and we will receive payments to the extent that such revenues exceed those thresholds. To the extent we receive any such payments, our actual gross payments over the 20 years could exceed $100 million. In September 2003, the first ship was delivered to its owner and in July 2005, the second ship was delivered to its owner. Both agreements represent a VIE, but we are not the primary beneficiary and, therefore, we do not consolidate these entities. The amount drawn under the guarantee facilities at December 31, 2007, was approximately $5 million for both ships. We currently account for these agreements as guarantees and contingent liabilities. See Note 17 — Guarantees, for additional information.

In 1997, Phillips 66 Capital II (Trust II) was created for the sole purpose of issuing mandatorily redeemable preferred securities to third-party investors and investing the proceeds thereof in an approximate amount of subordinated debt securities of ConocoPhillips. At December 31, 2006, we reported debt of $361 million of 8% Junior Subordinated Deferrable Interest Debentures due 2037.

Trust II is a VIE, but we do not consolidate it in our financial statements because we are not the primary beneficiary. Effective January 15, 2007, we redeemed the 8% Junior Subordinated Deferrable Interest Debentures due 2037 at a premium of $14 million, plus accrued interest. See Note 15 — Debt, for additional information about Trust II.

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

Ashford Energy Capital S.A. (Ashford) is consolidated in our financial statements because we are the primary beneficiary. In December 2001, in order to raise funds for general corporate purposes, ConocoPhillips and Cold Spring Finance S.a.r.l. (Cold Spring) formed Ashford through the contribution of a $1 billion ConocoPhillips subsidiary promissory note and $500 million cash. Through its initial $500 million investment, Cold Spring is entitled to a cumulative annual preferred return, based on three-month LIBOR rates, plus 1.32 percent. The preferred return at December 31, 2007, was 6.55 percent. In 2008, and each 10-year anniversary thereafter, Cold Spring may elect to remarket their investment in Ashford, and if unsuccessful, could require ConocoPhillips to provide a letter of credit in support of Cold Spring's investment, or in the event that such letter of credit is not provided, then cause the redemption of their investment in Ashford. Should ConocoPhillips' credit rating fall below investment grade, Ashford would require a letter of credit to support $475 million of the term loans, as of December 31, 2007, 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, 2007, Ashford held $2.0 billion of ConocoPhillips subsidiary notes and $29 million in investments unrelated to ConocoPhillips. We report Cold Spring's investment as a minority interest because it is not mandatorily redeemable and the entity does not have a specified liquidation date. Other than the obligation to make payment on the subsidiary notes described above, Cold Spring does not have recourse to our general credit.

Note 8 — Inventories

Inventories at December 31 were:

	Millions of Dollars	
	2007	2006
Crude oil and petroleum products	**$3,373**	4,351
Materials, supplies and other	**850**	802
	$4,223	5,153

Inventories valued on a LIFO basis totaled $2,974 million and $4,043 million at December 31, 2007 and 2006, respectively. The remainder of our inventories is valued under various methods, including FIFO and weighted average. The excess of current replacement cost over LIFO cost of inventories amounted to $6,668 million and $4,178 million at December 31, 2007 and 2006, respectively.

During 2007, certain inventory quantity reductions caused a liquidation of LIFO inventory values. This liquidation increased net income $280 million, of which $260 million was attributable to our R&M segment. In 2006, a liquidation of LIFO inventory values increased net income $39 million, of which $32 million was attributable to our R&M segment. Comparable amounts in 2005 increased net income $16 million, of which $15 million was attributable to our R&M segment.

Note 9 — Assets Held for Sale

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

At December 31, 2006, we classified $3,051 million of non-current assets as "Prepaid expenses and other current assets" on our consolidated balance sheet and we classified $604 million of non-current liabilities as current liabilities, consisting of $201 million in "Accrued income and other taxes" and $403 million in "Other accruals."

During 2007, 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, 2007, we classified $1,092 million of non-current assets as "Prepaid expenses and other current assets" on our consolidated balance sheet and we classified $159 million of non-current liabilities as current liabilities, consisting of $133 million in "Accrued income and other taxes" and $26 million in "Other accruals." We expect the disposal of these assets to be completed by the end of 2008.

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

	Millions of Dollars	
	2007	2006
Assets		
Investments and long-term receivables	**$ 48**	170
Net properties, plants and equipment	**946**	2,422
Goodwill	**89**	340
Intangibles	**2**	13
Other assets	**7**	106
Total assets reclassified	**$ 1,092**	3,051
Exploration and Production	**$ 189**	1,465
Refining and Marketing	**903**	1,586
	$ 1,092	3,051
Liabilities		
Asset retirement obligations and accrued environmental costs	**$ 23**	386
Deferred income taxes	**133**	201
Other liabilities and deferred credits	**3**	17
Total liabilities reclassified	**$ 159**	604
Exploration and Production	**$ 35**	392
Refining and Marketing	**124**	212
	$ 159	604

Note 10 — Investments, Loans and Long-Term Receivables

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

	Millions of Dollars	
	2007	2006
Equity investments	**$30,408**	18,544
Loans and advances — related parties	**1,871**	1,118
Long-term receivables	**495**	442
Other investments	**554**	609
	$33,328	20,713

Equity Investments

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

- FCCL Oil Sands Partnership (FCCL) — 50 percent owned business venture with EnCana Corporation—produces heavy-oil in the Athabasca oil sands in northeast Alberta, as well as transports and sells the bitumen blend.
- WRB Refining LLC (WRB) — 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 (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 and develop oil and gas resources in the northern part of Russia's Timan-Pechora province.
- DCP Midstream, LLC (DCP Midstream) — 50 percent owned joint venture with Spectra Energy — owns and operates gas plants, gathering systems, storage facilities and fractionation plants. Effective January 2, 2007, Duke Energy Field Services, LLC (DEFS) formally changed its name to DCP Midstream.
- Chevron Phillips Chemical Co. LLC (CPChem) — 50 percent owned joint venture with Chevron Corporation — manufactures and markets petrochemicals and plastics.

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		
	2007	2006	2005
Revenues	**$143,686**	113,607	96,367
Income before income taxes	**19,807**	16,257	15,059
Net income	**15,229**	12,447	11,743
Current assets	**29,451**	24,820	23,652
Noncurrent assets	**90,939**	59,803	48,181
Current liabilities	**16,882**	15,884	14,727
Noncurrent liabilities	**26,656**	20,603	15,833

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, 2007, retained earnings included $4,053 million related to the undistributed earnings of affiliated companies, and distributions received from affiliates were $3,326 million, $3,294 million and $1,807 million in 2007, 2006 and 2005, respectively.

Business Ventures with EnCana

In October 2006, we announced a business venture with EnCana Corporation (EnCana) to create an integrated North American heavy-oil business. The transaction closed on January 3, 2007, and consists of two 50/50 business ventures, a Canadian upstream general partnership, FCCL Oil Sands Partnership (FCCL), and a U.S. downstream limited liability company, WRB Refining LLC (WRB). 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 northeast 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 16 — 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 $5.0 billion was created due to the fair value of the contributed assets recorded by WRB exceeding their historic book value. The difference is 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, 2007, was approximately $4.8 billion. 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. In 2004, we made a joint announcement with LUKOIL of an agreement to form a broad-based strategic alliance, whereby we would become a strategic equity investor in LUKOIL.

During the January 24, 2005, extraordinary general meeting of LUKOIL shareholders, all charter amendments reflected in the Shareholder Agreement were passed and ConocoPhillips' nominee was elected to LUKOIL's Board. The Shareholder Agreement limits our ownership interest in LUKOIL to 20 percent of the shares authorized and issued and limits our ability to sell our LUKOIL shares for a period of four years from September 29, 2004, except in certain circumstances. Our ownership interest in LUKOIL was 16.1 percent at December 31, 2005, and 20 percent at both December 31, 2006 and 2007, based on 851 million shares authorized and issued.

For financial reporting under U.S. generally accepted accounting principles, treasury shares held by LUKOIL are not considered outstanding for determining our equity-method ownership interest in LUKOIL. Our ownership interest, based on estimated shares outstanding, was 20.6 percent at December 31, 2007 and 2006.

Because LUKOIL's accounting cycle close and preparation of U.S. generally accepted accounting principles (GAAP) financial statements occur subsequent to our reporting deadline, our equity earnings and statistics for our LUKOIL investment are estimated, based on current market indicators, publicly available LUKOIL operating results, 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 2007 and the actual LUKOIL U.S. GAAP net income will be reported in our 2008 equity earnings. At December 31, 2007, the book value of our ordinary share investment in LUKOIL was $11,162 million. Our 20 percent share of the net assets of LUKOIL was estimated to be $8,627 million. This basis difference of $2,535 million is primarily being amortized on a unit-of-production basis. Included in net income for 2007, 2006 and 2005 was after-tax expense of $76 million, $41 million and $43 million, respectively, representing the amortization of this basis difference.

On December 31, 2007, the closing price of LUKOIL shares on the London Stock Exchange was $86.50 per share, making the aggregate total market value of our LUKOIL investment $14,715 million.

OOO Naryanmarneftegaz

OOO Naryanmarneftegaz (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 ownership interest with a 50 percent governance interest. NMNG is working to develop the Yuzhno Khylchuyu (YK) field. Production from the NMNG joint venture fields is transported via pipeline to LUKOIL's existing terminal at Varandey Bay on the Barents Sea and then shipped via tanker to international markets.

We use the equity method of accounting for this joint venture and the book value of our investment in the venture at December 31, 2007, was $1,662 million.

DCP Midstream

DCP Midstream owns and operates gas plants, gathering systems, storage facilities and fractionation plants. In July 2005, ConocoPhillips and Duke Energy Corporation (Duke) restructured their respective ownership levels in DCP Midstream, which resulted in DCP Midstream becoming a jointly controlled venture, owned 50 percent by each company. This restructuring increased our ownership in DCP Midstream to 50 percent from 30.3 percent through a series of direct and indirect transfers of certain Canadian Midstream assets from DCP Midstream to Duke, a disproportionate cash distribution from DCP Midstream to Duke from the sale of DCP Midstream's interest in TEPPCO Partners, L.P., and a combined payment by ConocoPhillips to Duke and DCP Midstream of approximately $840 million. Our interest in the Empress plant in Canada was not included in the initial transaction as originally anticipated due to weather-related damage to the facility. Subsequently, the Empress plant was sold to Duke on August 1, 2005, for approximately $230 million. In the first quarter of 2005, as a part of equity earnings, we recorded our $306 million (after-tax) equity share of the gain from DCP Midstream's sale of its interest in TEPPCO.

At December 31, 2007, the book value of our common investment in DCP Midstream was $998 million.

Our 50 percent share of the net assets of DCP Midstream was $982 million. This difference of $16 million is being amortized on a straight-line basis through 2014 consistent with the remaining estimated useful lives of DCP Midstream's properties, plants and equipment.

DCP Midstream markets a portion of its natural gas liquids to us and CPChem under a supply agreement that continues until December 31, 2014. This purchase commitment is on an "if-produced, will-purchase" basis so it has no fixed production schedule, but has been, and is expected to be, a relatively stable purchase pattern over the term of the contract. Natural gas liquids are purchased under this agreement at various published market index prices, less transportation and fractionation fees.

CPChem

CPChem manufactures and markets petrochemicals and plastics. At December 31, 2007, the book value of our investment in CPChem was $2,203 million. Our 50 percent share of the total net assets of CPChem was $2,080 million. This basis difference of $123 million is being amortized through 2020, consistent with the remaining estimated useful lives of CPChem properties, plants and equipment.

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

Investments in Venezuela

See the "Expropriated Assets" section of Note 13 — Impairments, for information on the complete impairment of our investments in the Hamaca and Petrozuata projects.

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 will provide loan financing of approximately $631 million, excluding accrued interest, for the construction of an LNG facility. Through December 31, 2007, we have provided $594 million in loan financing, and an additional $87 million of accrued interest. See Note 7 — Variable Interest Entities (VIEs), for additional information.
- We have an obligation to provide loan financing to Varandey Terminal Company for 30 percent of the costs of the terminal expansion. We estimate our total loan obligation for the terminal expansion to be approximately $416 million at current exchange rates, excluding interest to be accrued during construction. This amount will be adjusted as the project's cost estimate and schedule are updated and the ruble exchange rate fluctuates. Through December 31, 2007, we had provided $331 million in loan financing, and an additional $32 million of accrued interest. See Note 7 — Variable Interest Entities (VIEs), for additional information.
- Qatargas 3 is an integrated project to produce and liquefy natural gas from Qatar's North field. We own a 30 percent interest in the project. The other participants in the project are affiliates of Qatar Petroleum (68.5 percent) and Mitsui & Co., Ltd. (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, excluding accrued interest. Upon completion certification, which is expected in 2010, all project loan facilities, including the ConocoPhillips loan facilities, will become non-recourse to the project participants. At December 31, 2007, Qatargas 3 had $2.4 billion outstanding under all the loan facilities, of which ConocoPhillips provided $690 million, and an additional $43 million of accrued interest.

Note 11 — Properties, Plants and Equipment

Properties, plants and equipment (PP&E) are recorded at cost. Within the E&P segment, depreciation is 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					
	2007			2006		
	Gross PP&E	Accum. DD&A	Net PP&E	Gross PP&E	Accum. DD&A	Net PP&E
E&P	**$102,550**	**30,701**	**71,849**	88,592	21,102	67,490
Midstream	**267**	**103**	**164**	330	157	173
R&M	**19,926**	**4,733**	**15,193**	22,115	5,199	16,916
LUKOIL Investment	**—**	**—**	**—**	—	—	—
Chemicals	**—**	**—**	**—**	—	—	—
Emerging Businesses	**1,204**	**138**	**1,066**	1,006	98	908
Corporate and Other	**1,414**	**683**	**731**	1,229	515	714
	$125,361	**36,358**	**89,003**	113,272	27,071	86,201

Suspended Wells

In April 2005, the FASB issued FSP FAS 19-1, "Accounting for Suspended Well Costs" (FSP FAS 19-1).

This FSP was issued to address whether there were circumstances that would permit the continued capitalization of exploratory well costs beyond one year, other than when further exploratory drilling is planned and major capital expenditures would be required to develop the project. We adopted FSP FAS 19-1 effective January 1, 2005. There was no impact on our consolidated financial statements from the adoption.

The following table reflects the net changes in suspended exploratory well costs during 2007, 2006 and 2005:

	Millions of Dollars		
	2007	2006	2005
Beginning balance at January 1	**$537**	339	347
Additions pending the determination of proved reserves	**157**	225	183
Reclassifications to proved properties	**(58)**	(8)	(81)
Sales of suspended well investment	**(22)**	—	—
Charged to dry hole expense	**(25)**	(19)	(110)
Ending balance at December 31	**$589***	537*	339

**Includes $7 million and $29 million related to assets held for sale in 2007 and 2006, respectively. See Note 9 — Assets Held for Sale, for additional information.*

The following table provides an aging of suspended well balances at December 31, 2007, 2006 and 2005:

	Millions of Dollars		
	2007	2006	2005
Exploratory well costs capitalized for a period of one year or less	**$153**	225	183
Exploratory well costs capitalized for a period greater than one year	**436**	312	156
Ending balance	**$589**	537	339
Number of projects that have exploratory well costs that have been capitalized for a period greater than one year	**35**	22	15

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, 2007:

	Millions of Dollars						
		Suspended Since					
Project	Total	2006	2005	2004	2003	2002	2001
Aktote — Kazakhstan[2]	$ 19	—	—	7	12	—	—
Alpine satellite — Alaska[2]	23	—	—	—	—	23	—
Caldita — Australia[1]	78	45	33	—	—	—	—
Clair — U.K.[1]	17	17	—	—	—	—	—
Enochdhu/Finlaggen — U.K.[1]	11	11	—	—	—	—	—
Humphrey — U.K.[2]	12	12	—	—	—	—	—
Jasmine — U.K.[1]	28	28	—	—	—	—	—
K4 — U.K.[2]	12	12	—	—	—	—	—
Kairan — Kazakhstan[2]	13	—	—	13	—	—	—
Kashagan — Kazakhstan[1]	18	—	—	—	9	—	9
Malikai — Malaysia[2]	50	17	22	11	—	—	—
Plataforma Deltana — Venezuela[2]	21	—	6	15	—	—	—
Su Tu Trang — Vietnam[2]	32	16	8	—	8	—	—
Uge — Nigeria[1]	14	—	14	—	—	—	—
West Sak — Alaska[2]	10	6	3	1	—	—	—
Twenty projects of less than $10 million each[1,2]	78	48	20	3	3	4	—
Total of 35 projects	$436	212	106	50	32	27	9

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

Note 12 — Goodwill and Intangibles

Changes in the carrying amount of goodwill are as follows:

	Millions of Dollars		
	E&P	R&M	Total
Balance at December 31, 2005	$11,423	3,900	15,323
Acquired (Burlington Resources)	16,615	—	16,615
Acquired (Wilhelmshaven)	—	229	229
Goodwill allocated to assets held for sale or sold	(216)	(354)	(570)
Tax and other adjustments	(110)	1	(109)
Balance at December 31, 2006	27,712	3,776	31,488
Goodwill allocated to expropriated assets	**(1,925)**	—	**(1,925)**
Acquired (Burlington Resources)	**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**

In the second quarter of 2007, we recorded a non-cash impairment related to the expropriation of our oil interests in Venezuela. The impairment included $1,925 million of goodwill allocated to the expropriation event. For additional information, see the "Expropriated Assets" section of Note 13 — Impairments.

On March 31, 2006, we acquired Burlington Resources Inc., an independent exploration and production company. As a result of this acquisition, we recorded goodwill of $16,787 million, all of which was assigned to our Worldwide E&P reporting unit. See Note 5 — Acquisition of Burlington Resources Inc., for additional information.

On February 28, 2006, we acquired the Wilhelmshaven refinery, located in Wilhelmshaven, Germany. The purchase included the refinery, a marine terminal, rail and truck loading facilities and a tank farm, as well as another entity that provides commercial and administrative support to the refinery. As a result of this acquisition, we recorded goodwill of $229 million, all of which was assigned to our Worldwide R&M reporting unit. The allocation of the purchase price to specific assets and liabilities was based on an estimate of the fair values of the fixed assets and various other assets and liabilities acquired. This goodwill is not deductible for tax purposes.

Information on the carrying value of intangible assets follows:

	Millions of Dollars		
	Gross Carrying Amount	Accumulated Amortization	Net Carrying Amount
Amortized Intangible Assets			
Balance at December 31, 2007			
Technology related	**$145**	**(60)**	**85**
Refinery air permits	**14**	**(8)**	**6**
Contract based	**124**	**(62)**	**62**
Other	**37**	**(25)**	**12**
	$320	**(155)**	**165**
Balance at December 31, 2006			
Technology related	$144	(51)	93
Refinery air permits	32	(12)	20
Contract based	139	(44)	95
Other	31	(24)	7
	$346	(131)	215
Indefinite-Lived Intangible Assets			
Balance at December 31, 2007			
Trade names and trademarks	**$494**		
Refinery air and operating permits	**237**		
	$731		
Balance at December 31, 2006			
Trade names and trademarks	$494		
Refinery air and operating permits	242		
	$736		

In addition to the above amounts, we had $2 million of intangibles classified as held for sale at December 31, 2007, and $13 million at December 31, 2006. See Note 9 — Assets Held for Sale, for additional information.

During 2007, we contributed $11 million of amortized intangible assets and $5 million of indefinite-lived intangible assets to the downstream business venture with EnCana.

Amortization expense related to the intangible assets above for the years ended December 31, 2007 and 2006, was $54 million and $56 million, respectively. The estimated amortization expense for 2008 is approximately $45 million. It is expected to be approximately $20 million per year for 2009 through 2012.

Note 13 — Impairments

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 non-cash 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 Exploration and Production 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.

Negotiations continue between ConocoPhillips and Venezuelan authorities concerning appropriate compensation for the expropriation of the company's interests. We continue to preserve all our rights with respect to this situation, including our rights under the contracts we signed and under international and Venezuelan law. We continue to evaluate our options in realizing adequate compensation for the value of our oil investments and operations in Venezuela and 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.

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.

At December 31, 2006, we had 1,088 million barrels of oil equivalent of proved reserves related to Petrozuata and Hamaca, and 17 million barrels of oil equivalent of proved reserves related to Corocoro. The loss of proved reserves related to these projects has been reflected as a sale in our 2007 reserves disclosures.

Other Impairments

During 2007, 2006 and 2005, we recognized the following before-tax impairment charges, excluding the impairment of expropriated assets:

	Millions of Dollars		
	2007	2006	2005
E&P			
United States	$ 73	55	2
International	398	160	2
Midstream	—	—	30
R&M			
Goodwill and intangible assets	—	300	—
Other	91	168	8
Increase in fair value of previously impaired assets	(128)	—	—
Corporate	8	—	—
	$ 442	683	42

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" line of the consolidated income statement.

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

In 2005, the E&P segment's impairments were the result of the write-down to market value of properties planned for disposition and properties failing to meet recoverability tests. The Midstream segment recognized property impairments related to planned asset dispositions. Other impairments in R&M primarily were related to assets planned for disposition.

Note 14 — Asset Retirement Obligations and Accrued Environmental Costs

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

	Millions of Dollars	
	2007	2006
Asset retirement obligations	$6,613	5,402
Accrued environmental costs	1,089	1,062
Total asset retirement obligations and accrued environmental costs	7,702	6,464
Asset retirement obligations and accrued environmental costs due within one year*	(441)	(845)
Long-term asset retirement obligations and accrued environmental costs	$7,261	5,619

**Classified as a current liability on the balance sheet, under the caption "Other accruals." Includes $23 million and $386 million related to assets held for sale in 2007 and 2006, respectively. See Note 9 — Assets Held for Sale, for additional information.*

Asset Retirement Obligations

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

In March 2005, the FASB issued FASB Interpretation No. 47, "Accounting for Conditional Asset Retirement Obligations — an interpretation of FASB Statement No. 143" (FIN 47). This Interpretation clarifies that an entity is required to recognize a liability for a legal obligation to perform asset retirement activities when the retirement is conditional on a future event and if the liability's fair value can be reasonably estimated. We implemented FIN 47 effective December 31, 2005. Accordingly, there was no impact on income from continuing operations in 2005. Application of FIN 47 increased net properties, plants and equipment by $269 million, and increased asset retirement obligation liabilities by $417 million.

The cumulative effect of this accounting change decreased 2005 net income by $88 million (after reduction of income taxes of $60 million).

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

SFAS No. 143 calls for measurements of asset retirement obligations to include, as a component of expected costs, an estimate of the price that a third party would demand, and could expect to receive, for bearing the uncertainties and unforeseeable circumstances inherent in the obligations, sometimes referred to as a market-risk premium. To date, the oil and gas industry has no examples of credit-worthy third parties who are willing to assume this type of risk, for a determinable price, on major oil and gas production facilities and pipelines. Therefore, because determining such a market-risk premium would be an arbitrary process, we excluded it from our SFAS No. 143 and FIN 47 estimates.

During 2007 and 2006, our overall asset retirement obligation changed as follows:

	Millions of Dollars	
	2007	2006
Balance at January 1	**$5,402**	3,901
Accretion of discount	**310**	248
New obligations	**76**	154
Burlington Resources acquisition	**—**	732
Changes in estimates of existing obligations	**843**	299
Spending on existing obligations	**(146)**	(130)
Property dispositions	**(259)***	(20)
Foreign currency translation	**395**	218
Expropriation of Venezuela assets	**(8)**	—
Balance at December 31	**$6,613**	5,402

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

The following table presents the estimated 2005 pro forma effects of the retroactive application of the adoption of FIN 47 as if the Interpretation had been adopted on the date the obligations arose:

	Millions of Dollars Except Per Share Amounts
Pro forma net income*	$13,600
Pro forma earnings per share	
Basic	9.76
Diluted	9.60

**Net income of $13,529 million for 2005 has been adjusted to remove the $88 million cumulative effect of the change in accounting principle attributable to FIN 47.*

Accrued Environmental Costs

Total environmental accruals at December 31, 2007 and 2006, were $1,089 million and $1,062 million, respectively. The 2007 increase in total accrued environmental costs is due to new accruals and accretion, partially offset by payments on accrued environmental costs.

We had accrued environmental costs of $740 million and $669 million at December 31, 2007 and 2006, 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 $255 million and $283 million of environmental costs associated with non-operating sites at December 31, 2007 and 2006, respectively. In addition, $94 million and $110 million were included at December 31, 2007 and 2006, 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 $836 million at December 31, 2007. The expected future undiscounted payments related to the portion of the accrued environmental costs that have been discounted are: $122 million in 2008, $136 million in 2009, $90 million in 2010, $46 million in 2011, $41 million in 2012, and $516 million for all future years after 2012.

Note 15 — Debt

Long-term debt at December 31 was:

	Millions of Dollars	
	2007	2006
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
8% Junior Subordinated Deferrable Interest Debentures due 2037	**—**	361
7.9% Debentures due 2047	**100**	100
7.8% Debentures due 2027	**300**	300
7.68% Notes due 2012	**37**	43
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 2007	**—**	153
7.25% Notes due 2031	**500**	500
7.20% Notes due 2031	**575**	575
7.125% Debentures due 2028	**300**	300
7% Debentures due 2029	**200**	200
6.95% Notes due 2029	**1,549**	1,549
6.875% Debentures due 2026	**67**	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**	—
5.95% Notes due 2036	**500**	500
5.90% Notes due 2032	**505**	505
5.625% Notes due 2016	**1,250**	1,250
5.50% Notes due 2013	**750**	750
5.30% Notes due 2012	**350**	350
4.75% Notes due 2012	**897**	897
Commercial paper at 4.05% – 5.36% at year-end 2007 and 5.27% – 5.47% at year-end 2006	**725**	2,931
Floating Rate Five-Year Term Note due 2011 at 5.0625% at year-end 2007 and 5.575% at year-end 2006	**3,000**	5,000
Floating Rate Notes due 2009 at 5.34% at year-end 2007 and 5.47% at year-end 2006	**950**	1,250
Floating Rate Notes due 2007 at 5.37% at year-end 2006	**—**	1,000
Industrial Development Bonds due 2012 through 2038 at 3.50% –5.75% at year-end 2007 and 3.60% – 5.75% at year-end 2006	**252**	252
Guarantee of savings plan bank loan payable due 2015 at 5.40% at year-end 2007 and 5.65% at year-end 2006	**175**	203
Note payable to Merey Sweeny, L.P. due 2020 at 7%*	**172**	180
Marine Terminal Revenue Refunding Bonds due 2031 at 3.40% – 3.51% at year-end 2007 and 3.68% at year-end 2006	**265**	265
Other	**50**	60
Debt at face value	**20,945**	26,372
Capitalized leases	**54**	44
Net unamortized premiums and discounts	**688**	718
Total debt	**21,687**	27,134
Notes payable and long-term debt due within one year	**(1,398)**	(4,043)
Long-term debt	**$20,289**	23,091

**Related party.*

Maturities of long-term borrowings, inclusive of net unamortized premiums and discounts, in 2008 through 2012 are: $1,398 million, $1,320 million, $1,483 million, $5,215 million and $2,028 million, respectively. At year-end 2007, notes payable and long-term debt due within one year of $1,398 million includes $1 billion of our Floating Rate Five-Year Term Note due 2011 repaid in January 2008, and $300 million of our 7.125% Debentures due 2028 that will be redeemed in March 2008.

At December 31, 2007, we had classified $725 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.

Effective January 15, 2007, we redeemed the 8% Junior Subordinated Deferrable Interest Debentures due 2037 (Subordinated Debt Securities II), at a premium of $14 million, plus accrued interest. This redemption resulted in the immediate redemption by Phillips 66 Capital II of $350 million of 8% Capital Securities. Under the provisions of revised FASB Interpretation No. 46, "Consolidation of Variable Interest Entities" (FIN 46 (R)), Trust II, a variable interest entity, was not consolidated in our financial statements because we were not the primary beneficiary. However, the Subordinated Debt Securities II ($361 million) was included on our consolidated balance sheet in "Notes payable and long-term debt due within one year" at December 31, 2006.

Also, in January 2007, we redeemed our $153 million 7.25% Notes due 2007 upon their maturity. In February 2007, we reduced our Floating Rate Five-Year Term Note due 2011 from $5 billion to $4 billion, with a subsequent reduction in July 2007 to $3 billion. In April 2007, we redeemed our $1 billion Floating Rate Notes due 2007 upon their maturity. In October 2007, we redeemed $300 million of Floating Rate Notes due 2009 at par plus accrued interest.

In May 2007, Polar Tankers Inc., a wholly owned subsidiary, issued an offering of $645 million 5.951% Notes due 2037. The notes are fully and unconditionally guaranteed by ConocoPhillips and ConocoPhillips Company.

In September 2007, we replaced our $5 billion and $2.5 billion revolving credit facilities, with one $7.5 billion revolving credit facility, expiring in September 2012. This facility may be used as direct bank borrowings, as support for the ConocoPhillips $7.5 billion commercial paper program, as support for the ConocoPhillips Qatar Funding Ltd. $1.5 billion commercial paper program, or as support for issuances of letters of credit totaling up to $750 million. The facility is broadly syndicated among financial institutions and does not contain any material adverse change provisions or covenants requiring maintenance of specified financial ratios or ratings. The credit agreement contains 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. At December 31, 2007 and 2006, we had no outstanding borrowings under these credit facilities, but $41 million in letters of credit had been issued at both dates. Under both commercial paper programs there was $725 million of commercial paper outstanding at December 31, 2007, compared with $2,931 million at December 31, 2006.

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 December 2007, we terminated interest rate swaps on $350 million of our 4.75% Notes due 2012. No interest rate swaps remain on any of our debt.

Note 16 — 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 accrued 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 $593 million was short-term at December 31, 2007, and is included in the "Accounts payable — related parties" line on our consolidated balance sheet. The principal portion of these payments, which totaled $425 million in 2007, is presented on our consolidated statement of cash flows as an other financing activity. Interest accrues at a fixed annual rate of 5.3 percent on the unpaid principal balance. Fifty percent of the quarterly interest payment is reflected as an additional capital contribution and is included in the "Capital expenditures and investments" line on our consolidated statement of cash flows.

Note 17 — Guarantees

At December 31, 2007, 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.

Construction Completion Guarantees

- In June 2006, we issued a guarantee for 24 percent of the $2 billion in credit facilities of Rockies Express Pipeline LLC (Rockies Express), which will be used to construct a natural gas pipeline across a portion of the United States. At December 31, 2007, Rockies Express had $1,625 million outstanding under the credit facilities, with our 24 percent guarantee equaling $390 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 facility is 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 in September 2007. It is anticipated final construction completion will be achieved in 2009, and refinancing will take place at that time, making the debt non-recourse to ConocoPhillips. At December 31, 2007, the total carrying value of these guarantees to third-party lenders was $12 million. See Note 7 — Variable Interest Entities (VIEs), for additional information.
- In December 2005, we issued a construction completion guarantee for 30 percent of the $4.0 billion in loan facilities of Qatargas 3, which will be used to construct an LNG train in Qatar. Of the $4.0 billion in loan facilities, ConocoPhillips has committed to provide $1.2 billion. The maximum potential amount of future payments to third-party lenders under the guarantee is estimated to be $850 million, which could become payable if the full debt financing is utilized and completion of the Qatargas 3 project is not achieved. The project financing will be non-recourse to ConocoPhillips upon certified completion, which is expected in 2010. At December 31, 2007, the carrying value of the guarantee to the third-party lenders was $11 million. For additional information, see Note 10 — Investments, Loans and Long-Term Receivables.

Guarantees of Joint-Venture Debt

- At December 31, 2007, we had 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

- The Merey Sweeny, L.P. (MSLP) joint-venture project agreement requires the partners in the venture to pay cash calls to cover operating expenses in the event the venture does not have enough cash to cover operating expenses after setting aside the amount required for debt service over the next 17 years. Although there is no maximum limit stated in the agreement, the intent is to cover short-term cash deficiencies should they occur. Our maximum potential future payments under the agreement are currently estimated to be $100 million, assuming such a shortfall exists at some point in the future due to an extended operational disruption.
- In February 2003, we entered into two agreements establishing separate guarantee facilities of $50 million each for two LNG ships. Subject to the terms of each such facility, we will be required to make payments should the charter revenue generated by the respective ship fall below certain specified minimum thresholds, and we will receive payments to the extent that such revenues exceed those thresholds. The net maximum future payments that we may have to make over the 20-year terms of the two agreements could be up to $100 million in total. To the extent we receive any such payments, our actual gross payments over the 20 years could exceed that amount. In the event either ship is sold or a total loss occurs, we also may have recourse to the sales or insurance proceeds to recoup payments made under the guarantee facilities. For additional information, see Note 7— Variable Interest Entities (VIEs).
- We have guarantees of the residual value of leased corporate aircraft. The maximum potential payment under these guarantees at December 31, 2007, was $150 million.
- In December 2007, we acquired a 50 percent equity interest in the Keystone Oil Pipeline (Keystone) to form a 50/50 joint venture with TransCanada Corporation. Keystone plans to construct a crude oil pipeline originating in Hardisty, Alberta, with delivery points at Wood River and Patoka, Illinois, and

Cushing, Oklahoma. In connection with certain planning and construction activities, agreements were put in place with third parties to guarantee the payments due. Our maximum potential amount of future payments under those agreements are estimated to be $400 million, which could become payable if Keystone fails to meet its obligations under the agreements noted above and the obligation 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 that payments would be required. All but $15 million of the guarantees will terminate after construction is completed, currently estimated to be in 2010.

- We have other guarantees with maximum future potential payment amounts totaling $200 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, one small construction completion guarantee, guarantees relating to the startup of a refining joint venture, and guarantees of the lease payment obligations of a joint venture. These guarantees generally extend up to 10 years or life of the venture and payment would be required only if the dealer, jobber or lessee goes into default, if the joint ventures have cash liquidity issues, if a construction project is not completed, if a guaranteed party defaults on lease payments, or if an adverse decision occurs in the pending lawsuit.

Indemnifications

Over the years, we have entered into various agreements to sell ownership interests in certain corporations and joint ventures and have sold several assets, including downstream and midstream assets, certain exploration and production assets, and downstream retail and wholesale sites 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, 2007, was $471 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 $294 million of environmental accruals for known contamination that is included in asset retirement obligations and accrued environmental costs at December 31, 2007. For additional information about environmental liabilities, see Note 18 — Contingencies and Commitments.

Note 18 — 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 2 — Changes in Accounting Principles and Note 24 — 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 that they are both probable and reasonably estimable.

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

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

We are currently participating in environmental assessments and cleanups at numerous federal Superfund and comparable state sites. After an assessment of environmental exposures for cleanup and other costs, we make accruals on an undiscounted basis (except those acquired in a purchase business combination, which we record on a discounted basis) for planned investigation and remediation activities for sites where it is probable that future costs will be incurred and these costs can be reasonably estimated. We have not reduced these accruals for possible insurance recoveries. In the future, we may be involved in additional environmental assessments, cleanups and proceedings. See Note 14 — Asset Retirement Obligations and Accrued Environmental Costs, for a summary of our accrued environmental liabilities.

Legal Proceedings

Our legal 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 that there is only a remote likelihood that future costs related to known contingent liability exposures will exceed current accruals by an amount that would have a material adverse impact on our 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, 2007, we had performance obligations secured by letters of credit of $1,200 million (of which $41 million was issued under the provisions of our revolving credit facilities, and the remainder was issued as direct bank letters of credit) and various purchase commitments for materials, supplies, services and items of permanent investment incident to the ordinary conduct of business.

See Note 13 — 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: 2008 — $97 million; 2009 — $97 million; 2010 — $97 million; 2011 — $98 million; 2012 — $97 million; and 2013 and after — $542 million. Total payments under the agreements were $67 million in 2007, $66 million in 2006 and $52 million in 2005.

Note 19 — Financial Instruments and Derivative Contracts

Derivative Instruments

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

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

	Millions of Dollars	
	2007	2006
Derivative Assets		
Current	**$ 453**	924
Long-term	**89**	82
	$ 542	1,006
Derivative Liabilities		
Current	**$ 493**	681
Long-term	**67**	126
	$ 560	807

These derivative assets and liabilities appear as prepaid expenses and other current assets, other assets, other accruals, or other liabilities and deferred credits on the balance sheet.

In June 2005, we acquired two limited-term, fixed-volume overriding royalty interests in Utah and the San Juan Basin related to our natural gas production. As part of the acquisition, we assumed related commodity swaps with a negative fair value of $261 million at June 30, 2005. In late June and early July of 2005, we entered into additional commodity swaps to essentially offset any remaining exposure from the assumed swaps. At December 31, 2007 and 2006, the commodity swaps assumed in the acquisition had a negative fair value of $29 million and $76 million, respectively, and the commodity swaps entered into to offset the resulting exposure had a positive fair value of $2 million and a negative fair value of $6 million, respectively.

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

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.

Interest Rate Derivative Contracts — At the beginning of 2004, we held interest rate swaps that converted $1.5 billion of debt from fixed to floating rates, but during 2005 we terminated the majority of these interest rate swaps as we redeemed the associated debt. This reduced the amount of debt being converted from fixed to floating by the end of 2005 to $350 million. In December 2007, we sold our positions in these remaining swaps for approximately $3 million, terminating the hedge.

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

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, 2007, 2006 and 2005, 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 non-performance. We also use futures contracts, but futures have a negligible credit risk because they are traded on the New York Mercantile Exchange or the ICE Futures.

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

Fair Values of Financial Instruments

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

- Cash and cash equivalents: The carrying amount reported on the balance sheet approximates fair value.
- Accounts and notes receivable: The carrying amount reported on the balance sheet approximates fair value.
- Investment in LUKOIL shares: See Note 10 — Investments, Loans and Long-Term Receivables, for a discussion of the carrying value and fair value of our investment in LUKOIL shares.
- Debt: The carrying amount of our floating-rate debt approximates fair value. The fair value of the fixed-rate debt is estimated based on quoted market prices.
- 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 4.9 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 16 — Joint Venture Acquisition Obligation, for additional information.
- Swaps: Fair value is estimated based on forward market prices and approximates the net gains and losses that would have been realized if the contracts had been closed out at year-end. When forward market prices are not available, they are estimated using the forward prices of a similar commodity with adjustments for differences in quality or location.
- Futures: Fair values are based on quoted market prices obtained from the New York Mercantile Exchange, the ICE Futures, or other traded exchanges.
- Forward-exchange contracts: Fair value is estimated by comparing the contract rate to the forward rate in effect on December 31 and approximates the net gains and losses that would have been realized if the contracts had been closed out at year-end.

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

	Millions of Dollars			
	Carrying Amount		Fair Value	
	2007	2006	**2007**	2006
Financial assets				
Foreign currency derivatives	$ **47**	47	**47**	47
Commodity derivatives	**495**	959	**495**	959
Financial liabilities				
Total debt, excluding capital leases	**21,633**	27,090	**23,101**	27,741
Joint venture acquisition obligation	**6,887**	—	**7,031**	—
Foreign currency derivatives	**29**	26	**29**	26
Interest rate derivatives	**—**	10	**—**	10
Commodity derivatives	**531**	771	**531**	771

Note 20 — Preferred Stock and Minority Interests

Preferred Stock

We have 500 million shares of preferred stock authorized, par value $.01 per share, none of which was issued or outstanding at December 31, 2007 or 2006.

Minority Interests

The minority interest owner in Ashford Energy Capital S.A. is entitled to a cumulative annual preferred return on its investment, based on three-month LIBOR rates plus 1.32 percent. The preferred return at December 31, 2007 and 2006, was 6.55 percent and 6.69 percent, respectively. At December 31, 2007 and 2006, the minority interest was $508 million, for both periods. Ashford Energy Capital S.A. continues to be consolidated in our financial statements under the provisions of FIN 46(R) because we are the primary beneficiary. See Note 7 — Variable Interest Entities (VIEs), for additional information.

The remaining minority interest amounts are primarily related to equity in less than wholly owned consolidated subsidiaries. The largest amount, $648 million at December 31, 2007, and $672 million at December 31, 2006, relates to Darwin LNG located in northern Australia.

Note 21 — Preferred Share Purchase Rights

In 2002, our Board of Directors authorized and declared a dividend of one preferred share purchase right for each common share outstanding, and authorized and directed the issuance of one right per common share for any newly issued shares. The rights have certain anti-takeover effects. The rights will cause substantial dilution to a person or group that attempts to acquire ConocoPhillips on terms not approved by the Board of Directors. However, since the rights may either be redeemed or otherwise made inapplicable by ConocoPhillips prior to an acquiror obtaining beneficial ownership of 15 percent or more of

ConocoPhillips' common stock, the rights should not interfere with any merger or business combination approved by the Board of Directors prior to that occurrence. The rights, which expire June 30, 2012, will be exercisable only if a person or group acquires 15 percent or more of the company's common stock or commences a tender offer that would result in ownership of 15 percent or more of the common stock. Each right would entitle stockholders to buy one one-hundredth of a share of preferred stock at an exercise price of $300. If an acquiror obtains 15 percent or more of ConocoPhillips' common stock, then each right will be adjusted so that it will entitle the holder (other than the acquirer, whose rights will become void) to purchase, for the then exercise price, a number of shares of ConocoPhillips' common stock equal in value to two times the exercise price of the right. In addition, the rights enable holders to purchase the stock of an acquiring company at a discount, depending on specific circumstances. We may redeem the rights in whole, but not in part, for one cent per right.

Note 22 — Non-Mineral Leases

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

At December 31, 2007, future minimum rental payments due under non-cancelable leases were:

	Millions of Dollars
2008	$ 732
2009	593
2010	439
2011	340
2012	397
Remaining years	807
Total	3,308
Less income from subleases	(186)*
Net minimum operating lease payments	$ 3,122

**Includes $90 million related to railroad cars subleased to CPChem, a related party.*

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

	Millions of Dollars		
	2007	2006	2005
Total rentals*	**$ 855**	698	564
Less sublease rentals	**(82)**	(103)	(66)
	$ 773	595	498

**Includes $27 million, $29 million and $28 million of contingent rentals in 2007, 2006 and 2005, respectively. Contingent rentals primarily are related to retail sites and refining equipment, and are based on volume of product sold or throughput.*

Note 23 — Employee Benefit Plans

Pension and Postretirement Plans

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	
	2007		2006		**2007**	2006
	U.S.	**Int'l.**	U.S.	Int'l.		
Change in Benefit Obligation						
Benefit obligation at January 1	**$ 4,113**	**3,087**	3,703	2,495	**778**	815
Service cost	**175**	**98**	174	87	**14**	14
Interest cost	**229**	**161**	210	134	**45**	47
Plan participant contributions	**—**	**10**	—	9	**28**	31
Medicare Part D subsidy	**—**	**—**	—	—	**6**	6
Plan amendments	**2**	**(68)**	1	—	**—**	(26)
Actuarial (gain) loss	**109**	**(294)**	57	79	**(6)**	(59)
Acquisitions	**—**	**—**	275	42	**—**	36
Divestitures	**—**	**—**	—	—	**—**	—
Benefits paid	**(347)**	**(97)**	(307)	(77)	**(81)**	(86)
Curtailment	**—**	**1**	—	—	**—**	—
Recognition of termination benefits	**—**	**1**	—	1	**—**	—
Foreign currency exchange rate change	**—**	**186**	—	317	**8**	—
Benefit obligation at December 31*	**$ 4,281**	**3,085**	4,113	3,087	**792**	778
**Accumulated benefit obligation portion of above at December 31:*	***$ 3,666***	***2,550***	*3,493*	*2,585*		
Change in Fair Value of Plan Assets						
Fair value of plan assets at January 1	**$ 2,863**	**2,185**	2,183	1,725	**3**	3
Acquisitions	**—**	**—**	214	44	**—**	—
Divestitures	**—**	**—**	—	—	**—**	—
Actual return on plan assets	**237**	**169**	356	142	**—**	—
Company contributions	**385**	**185**	417	120	**47**	49
Plan participant contributions	**—**	**10**	—	9	**28**	31
Medicare Part D subsidy	**—**	**—**	—	—	**6**	6
Benefits paid	**(347)**	**(97)**	(307)	(77)	**(81)**	(86)
Foreign currency exchange rate change	**—**	**149**	—	222	**—**	—
Fair value of plan assets at December 31:	**$ 3,138**	**2,601**	2,863	2,185	**3**	3
Funded Status	**$(1,143)**	**(484)**	(1,250)	(902)	**(789)**	(775)
Amounts Recognized in the Consolidated Balance Sheet at December 31						
Noncurrent assets	**$ —**	**98**	—	16	**—**	—
Current liabilities	**(6)**	**(9)**	(3)	(11)	**(50)**	(48)
Noncurrent liabilities	**(1,137)**	**(573)**	(1,247)	(907)	**(739)**	(727)
Total recognized	**$(1,143)**	**(484)**	(1,250)	(902)	**(789)**	(775)

	Millions of Dollars					
	Pension Benefits				Other Benefits	
	2007		2006		2007	2006
	U.S.	Int'l.	U.S.	Int'l.		
Weighted-Average Assumptions Used to Determine Benefit Obligations at December 31						
Discount rate	**6.00%**	**5.90**	5.75	5.15	**6.20**	5.95
Rate of compensation increase	**4.00**	**4.80**	4.00	4.70	—	—
Weighted-Average Assumptions Used to Determine Net Periodic Benefit Cost for Years Ended December 31						
Discount rate	**5.75%**	**5.15**	5.50	5.05	**5.95**	5.70
Expected return on plan assets	**7.00**	**6.50**	7.00	6.50	**7.00**	7.00
Rate of compensation increase	**4.00**	**4.70**	4.00	4.35	—	—

For both U.S. and international pensions, the overall expected long-term rate of return is developed from the expected future return of each asset class, weighted by the expected allocation of pension assets to that asset class. We rely on a variety of independent market forecasts in developing the expected rate of return for each class of assets.

All of our plans use a December 31 measurement date, except for a plan in the United Kingdom, which has a September 30 measurement date. 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)," in 2008 the measurement date for the U.K. plan will be changed to December 31, which is expected to result in a $10 million charge to 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	
	2007		2006		2007	2006
	U.S.	Int'l.	U.S.	Int'l.		
Unrecognized net actuarial loss (gain)	**$587**	**123**	577	460	**(185)**	(200)
Unrecognized prior service cost	**71**	**(30)**	79	44	**15**	28

	Millions of Dollars		
	2007		
	Pension Benefits		Other Benefits
	U.S.	Int'l.	
Sources of Change in Other Comprehensive Income			
Net gain (loss) arising during the period	**$(72)**	**289**	**5**
Amortization of gain (loss) included in income	**62**	**48**	**(20)**
Net gain (loss) during the period	**$(10)**	**337**	**(15)**
Prior service cost arising during the period	**$ (2)**	**67**	**—**
Amortization of prior service cost included in income	**10**	**7**	**13**
Net prior service cost during the period	**$ 8**	**74**	**13**

Amounts included in accumulated other comprehensive income at December 31, 2007, that are expected to be amortized into net periodic postretirement cost during 2008 are provided below:

	Millions of Dollars		
	Pension		Other Benefits
	U.S.	Int'l.	
Unrecognized net actuarial loss (gain)	$64	12	(19)
Unrecognized prior service cost	10	1	13

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 $6,392 million, $5,417 million, and $5,056 million at December 31, 2007, respectively, and $6,366 million, $5,400 million, and $4,543 million at December 31, 2006, respectively.

For our unfunded non-qualified key employee supplemental pension plans, the projected benefit obligation and the accumulated benefit obligation were $390 million and $344 million, respectively, at December 31, 2007, and were $345 million and $304 million, respectively, at December 31, 2006.

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		
	2007		2006		2005		2007	2006	2005
	U.S.	Int'l.	U.S.	Int'l.	U.S.	Int'l.			
Components of Net Periodic Benefit Cost									
Service cost	**$ 175**	**98**	174	87	151	69	**14**	14	19
Interest cost	**229**	**161**	210	134	174	122	**45**	47	48
Expected return on plan assets	**(204)**	**(147)**	(169)	(121)	(126)	(105)	**—**	—	—
Amortization of prior service cost	**10**	**7**	9	7	4	7	**13**	19	19
Recognized net actuarial loss (gain)	**62**	**48**	89	41	55	33	**(20)**	(16)	(6)
Net periodic benefit cost	**$ 272**	**167**	313	148	258	126	**52**	64	80

We recognized pension settlement losses of $2 million and $11 million, special termination benefits of $1 million and $1 million, and curtailment losses of $1 million and $0 in 2007 and 2006, respectively.

In determining net pension and other postretirement benefit costs, we amortize prior service costs on a straight-line basis over the average remaining service period of employees expected to receive benefits under the plan. For net gains and losses, we amortize 10 percent of the unamortized balance each year.

We have multiple non-pension postretirement benefit plans for health and life insurance. The health care plans are contributory, with participant and company contributions adjusted annually; the life insurance plans are non-contributory. For most groups of retirees, any increase in the annual health care escalation rate above 4.5 percent is borne by the participant. The weighted-average health care cost trend rate for those pre-65 participants not subject to the cap is assumed to decrease gradually from 9.0 percent in 2008 to 5.5 percent in 2015. For post-65 participants not subject to the cap, the weighted-average health care cost trend rate is assumed to decrease gradually from 10.0 percent in 2008 to 5.5 percent in 2020.

The assumed health care cost trend rate impacts the amounts reported. A one-percentage-point change in the assumed health care cost trend rate would have the following effects on the 2007 amounts:

	Millions of Dollars	
	One-Percentage-Point	
	Increase	Decrease
Effect on total of service and interest cost components	$ 2	(3)
Effect on the postretirement benefit obligation	33	(39)

Plan Assets — We follow a policy of broadly diversifying pension plan assets across asset classes, investment managers, and individual holdings. Asset classes that are considered appropriate include U.S. equities, non-U.S. equities, U.S. fixed income, non-U.S. fixed income, real estate, and private equity investments. Plan fiduciaries may consider and add other asset classes to the investment program from time to time. Our funding policy for U.S. plans is to contribute at least the minimum required by the Employee Retirement Income Security Act of 1974. Contributions to foreign plans are dependent upon local laws and tax regulations. In 2008, we expect to contribute approximately $460 million to our domestic qualified and non-qualified benefit plans and $177 million to our international qualified and non-qualified benefit plans.

A portion of U.S. pension plan assets is held as a participating interest in an insurance annuity contract. This participating interest is calculated as the market value of investments held under this contract, less the accumulated benefit obligation covered by the contract. At December 31, 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. At December 31, 2006, the participating interest was valued at $181 million and consisted of $412 million in debt securities and $53 million in equity securities, less $284 million for the accumulated benefit obligation covered by the contract. 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		
	2007	2006	Target	**2007**	2006	Target
Asset Category						
Equity securities	**64%**	66	60	**48**	50	51
Debt securities	**36**	33	30	**46**	44	43
Real estate	**—**	—	5	**5**	5	5
Other	**—**	1	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	
	2007	2006	**2007**	2006
Asset Category				
Equity securities	**62%**	72	**48**	50
Debt securities	**33**	21	**46**	44
Participating interest in annuity contract	**5**	6	**—**	—
Real estate	**—**	—	**5**	5
Other	**—**	1	**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
2008	$ 326	98	55	7
2009	294	107	57	8
2010	320	111	60	9
2011	356	116	63	9
2012	391	123	64	10
2013–2017	2,537	730	342	61

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 pay in the thrift feature of the CPSP to a choice of approximately 32 investment funds. ConocoPhillips matches deposits, up to 1.25 percent of eligible pay. Company contributions charged to expense for the CPSP and predecessor plans, excluding the stock savings feature (discussed below), were $21 million in 2007, $19 million in 2006, and $18 million in 2005. 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 2007, ConocoPhillips contributed $5 million to the BR Savings Plan, to match eligible contributions by employees.

The stock savings feature of the CPSP is a leveraged employee stock ownership plan. Employees may elect to participate in the stock savings feature by contributing 1 percent of their salaries and receiving an allocation of shares of common stock proportionate to their contributions.

In 1990, the Long-Term Stock Savings Plan of Phillips Petroleum Company (now the stock savings feature of the CPSP) borrowed funds that were used to purchase previously unissued shares of company common stock. Since the company guarantees the CPSP's borrowings, the unpaid balance is reported as a liability of the company and unearned compensation is shown as a reduction of common stockholders' equity. Dividends on all shares are charged against retained earnings. The debt is serviced by the CPSP from company contributions and dividends received on certain shares of common stock held by the plan, including all unallocated shares. The shares held by the stock savings feature of the CPSP are released for allocation to participant accounts based on debt service payments on CPSP borrowings. In addition, during the period from 2008 through 2011, when no debt principal payments are scheduled to occur, the company has committed to make direct contributions of stock to the stock savings feature of the CPSP, or make prepayments on CPSP borrowings, to ensure a certain minimum level of stock allocation to participant accounts.

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 $148 million, $126 million and $124 million in 2007, 2006 and 2005, respectively, all of which was compensation expense. In 2007, 2006 and 2005, we contributed 1,856,224 shares, 1,921,688 shares and 2,250,727 shares, respectively, of company common stock from the Compensation and Benefits Trust. The shares had a fair market value of $155 million, $132 million and $130 million, respectively. Dividends used to service debt were $39 million, $37 million and $32 million in 2007, 2006 and 2005, respectively. These dividends reduced the amount of compensation expense recognized each period. Interest incurred on the CPSP debt in 2007, 2006 and 2005 was $11 million, $12 million and $9 million, respectively.

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

	2007	2006
Unallocated shares	**9,040,949**	10,499,837
Allocated shares	**17,648,368**	18,501,772
Total shares	**26,689,317**	29,001,609

The fair value of unallocated shares at December 31, 2007 and 2006, was $798 million and $755 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 $44 million in 2007, $39 million in 2006 and $27 million in 2005.

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, 2007, was as follows:

	Millions of Dollars		
	2007	2006	2005
Compensation cost	**$242**	140	226
Tax benefit	**85**	54	84

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, 2007:

	Options	Weighted-Average Exercise Price	Weighted-Average Grant-Date Fair Value	Millions of Dollars Aggregate Intrinsic Value
Outstanding at December 31, 2004	74,263,922	$25.97		
Granted	2,567,000	47.87	$10.92	
Exercised	(19,265,175)	24.85		$ 615
Forfeited/expired	(169,001)	34.83		
Outstanding at December 31, 2005	57,396,746	$27.31		
Burlington Resources acquisition at March 31, 2006	4,927,116	33.95		
Granted	1,809,281	59.33	$16.16	
Exercised	(9,737,765)	24.32		$ 416
Forfeited	(341,759)	60.58		
Expired	(4,840)	50.16		
Outstanding at December 31, 2006	54,048,779	$29.31		
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**		
Vested at December 31, 2007	**41,386,111**	**$30.26**		**$2,407**
Exercisable at December 31, 2007	**39,721,035**	**$28.86**		**$2,366**

The weighted-average remaining contractual term of vested options and exercisable options at December 31, 2007, was 4.44 years and 4.26 years, respectively.

During 2007, we received $316 million in cash and realized a tax benefit of $191 million from the exercise of options. At December 31, 2007, 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:

	2007	2006	2005
Assumptions used			
Risk-free interest rate	**4.77%**	4.63	3.92
Dividend yield	**2.50%**	2.50	2.50
Volatility factor	**26.10%**	26.10	22.50
Expected life (years)	**6.70**	7.18	7.18

The ranges in the assumptions used were as follows:

	2007		2006		2005	
	High	**Low**	High	Low	High	Low
Ranges used						
Risk-free interest rate	**4.90%**	**4.77**	5.15	4.54	4.45	3.33
Dividend yield	**2.50**	**2.50**	2.50	2.50	2.50	2.50
Volatility factor	**26.10**	**26.10**	26.50	25.90	25.70	22.30

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, 2007:

	Stock Units	Weighted-Average Grant-Date Fair Value	Millions of Dollars Total Fair Value
Outstanding at December 31, 2004	2,316,690	$32.10	
Granted	1,668,192	46.95	
Forfeited	(57,262)	37.81	
Issued	(35,216)		$ 2
Outstanding at December 31, 2005	3,892,404	$38.34	
Granted	1,480,294	57.77	
Forfeited	(118,461)	45.92	
Issued	(167,099)		$11
Outstanding at December 31, 2006	5,087,138	$43.75	
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**	
Not vested at December 31, 2007	**5,314,557**	**$50.61**	

At December 31, 2007, the remaining unrecognized compensation cost from the unvested units was $124 million, which will be recognized over a weighted-average period of 23 months, the longest period being 49 months.

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

The following summarizes our Performance Share Program activity for the two years ended December 31, 2007:

	Performance Share Stock Units	Grant-Date Fair Value	Millions of Dollars Total Fair Value
Outstanding at December 31, 2005	—	—	—
Granted	1,641,216	$59.08	
Forfeited/cancelled	—		
Issued	(184,975)		$12
Outstanding at December 31, 2006	1,456,241	$59.08	
Granted	**1,349,475**	**66.37**	
Forfeited	**(22,062)**		
Issued	**(178,357)**		**$12**
Outstanding at December 31, 2007	**2,605,297**	**$62.49**	
Not Vested at December 31, 2007	**1,198,599**	**$41.97**	

At December 31, 2007, the remaining unrecognized compensation cost from unvested Performance Share awards was $50 million, which will be recognized over a weighted-average period of 49 months, the longest period being 13 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, 2007:

	Stock Units	Weighted-Average Grant-Date Fair Value	Millions of Dollars Total Fair Value
Outstanding at December 31, 2004	3,461,899	$28.44	
Granted	89,676	54.08	
Stock swaps	9,116	43.97	
Issued	(135,168)		$ 7
Cancelled	(80,582)	28.93	
Outstanding at December 31, 2005	3,344,941	$29.16	
Granted	248,421	64.48	
Burlington Resources acquisition	523,769	64.95	
Issued	(239,257)		$16
Cancelled	(275,499)	47.56	
Outstanding at December 31, 2006	3,602,375	$33.68	
Granted	**293,024**	**67.30**	
Issued	**(227,766)**		**$17**
Cancelled	**(180,489)**	**50.39**	
Outstanding at December 31, 2007	**3,487,144**	**$34.41**	
Not vested at December 31, 2007	**370,303**	**$65.65**	

At December 31, 2007, 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 2007 and 2006, shares transferred out of the CBT were 1,856,224 and 1,921,688, respectively. At December 31, 2007, the CBT had 42.2 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 24 — Income Taxes

Income taxes charged to income from continuing operations were:

	Millions of Dollars		
	2007	2006	2005
Income Taxes			
Federal			
Current	**$ 3,944**	4,313	3,434
Deferred	**312**	(77)	375
Foreign			
Current	**7,035**	7,581	5,093
Deferred	**(474)**	392	384
State and local			
Current	**602**	622	538
Deferred	**(38)**	(48)	83
	$11,381	12,783	9,907

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	
	2007	2006
Deferred Tax Liabilities		
Properties, plants and equipment, and intangibles	**$23,344**	22,733
Investment in joint ventures	**1,300**	1,178
Inventory	**197**	339
Partnership income deferral	**1,501**	1,305
Other	**725**	438
Total deferred tax liabilities	**27,067**	25,993
Deferred Tax Assets		
Benefit plan accruals	**1,603**	1,730
Asset retirement obligations and accrued environmental costs	**3,135**	2,330
Deferred state income tax	**390**	408
Other financial accruals and deferrals	**539**	820
Loss and credit carryforwards	**1,716**	1,283
Other	**251**	230
Total deferred tax assets	**7,634**	6,801
Less valuation allowance	**(1,269)**	(822)
Net deferred tax assets	**6,365**	5,979
Net deferred tax liabilities	**$20,702**	20,014

Current assets, long-term assets, current liabilities and long-term liabilities included deferred taxes of $329 million, $26 million, $39 million and $21,018 million, respectively, at December 31, 2007, and $173 million, $62 million, $175 million and $20,074 million, respectively, at December 31, 2006.

We have loss and credit carryovers in multiple taxing jurisdictions. These attributes generally expire between 2008 and 2027 with some carryovers having indefinite carryforward periods.

Valuation allowances have been established for certain loss and credit carryforwards that reduce deferred tax assets to an amount that will, more likely than not, be realized. Uncertainties that may affect the realization of these assets include tax law changes and the future level of product prices and costs. During 2007, valuation allowances increased a total of $447 million. This reflects increases of $849 million primarily related to U.S. foreign tax credit and foreign tax loss carryforwards, partially offset by decreases of $402 million primarily related to foreign loss carryforwards (asset dispositions and relinquishment). The balance includes valuation allowances for certain deferred tax assets of $229 million, for which subsequently recognized tax benefits, if any, will be allocated to goodwill. Based on our historical taxable income, expectations for the future, and available tax-planning strategies, management expects that remaining net deferred tax assets will be realized as offsets to reversing deferred tax liabilities and as offsets to the tax consequences of future taxable income.

At December 31, 2007 and 2006, income considered to be permanently reinvested in certain foreign subsidiaries and foreign corporate joint ventures totaled approximately $4,381 million and $3,597 million, respectively. Deferred income taxes have not been provided on this income, as we do not plan to initiate any action that would require the payment of income taxes. It is not practicable to estimate the amount of additional tax that might be payable on this foreign income if distributed.

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.

	Millions of Dollars
Balance at January 1	$ 912
Additions based on tax positions related to the current year	273
Additions for tax positions of prior years	145
Reductions for tax positions of prior years	(168)
Settlements	(15)
Lapse of statute	(4)
Balance at December 31, 2007	$ 1,143

Included in the balance of unrecognized tax benefits was $698 million which, if recognized, would affect our effective tax rate.

At December 31, 2007, accrued liabilities for interest and penalties totaled $137 million, net of accrued income taxes. Interest and penalties affecting earnings in 2007 were $46 million.

We and our subsidiaries file tax returns in the U.S. federal jurisdiction and in many foreign and state jurisdictions. Audits in major jurisdictions, including the United States, Canada, Norway and the United Kingdom, are generally complete through 2001. 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 to our total unrecognized tax benefits, but the amount of change is not estimable.

The amounts of U.S. and foreign income from continuing operations before income taxes, with a reconciliation of tax at the federal statutory rate with the provision for income taxes, were:

	Millions of Dollars			Percent of Pretax Income		
	2007	2006	2005	**2007**	2006	2005
Income from continuing operations before income taxes						
United States	**$ 13,939**	13,376	12,486	**59.9%**	47.2	53.0
Foreign	**9,333**	14,957	11,061	**40.1**	52.8	47.0
	$ 23,272	28,333	23,547	**100.0%**	100.0	100.0
Federal statutory income tax	**$ 8,145**	9,917	8,241	**35.0%**	35.0	35.0
Foreign taxes in excess of federal statutory rate	**3,254**	2,697	1,562	**14.0**	9.5	6.6
Federal manufacturing deduction	**(250)**	(119)	(106)	**(1.1)**	(.4)	(.4)
State income tax	**367**	373	404	**1.6**	1.3	1.7
Other	**(135)**	(85)	(194)	**(.6)**	(.3)	(.8)
	$ 11,381	12,783	9,907	**48.9%**	45.1	42.1

Our effective tax rate in 2007 was 49 percent, compared with 45 percent in 2006. The change in the effective tax rate for 2007 was primarily due to the impact of the expropriation of our oil interests in Venezuela in the second quarter of 2007. This impact was partially offset by the effect of income tax law changes enacted during 2007, and by a higher proportion of income in higher tax rate jurisdictions during 2006.

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. Our 2005 tax expense was reduced $38 million due to the remeasurement of deferred tax liabilities from the 2003 Canadian graduated tax rate reduction.

Note 25 — Other Comprehensive Income (Loss)

The components and allocated tax effects of other comprehensive income (loss) follow:

	Millions of Dollars		
	Before-Tax	Tax Expense (Benefit)	After-Tax
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**
Non-sponsored 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
2005			
Minimum pension liability adjustment	$ (101)	(45)	(56)
Unrealized loss on securities	(10)	(4)	(6)
Foreign currency translation adjustments	(786)	(69)	(717)
Hedging activities	(3)	(4)	1
Other comprehensive loss	$ (900)	(122)	(778)

**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 in the equity section of the balance sheet included:

	Millions of Dollars	
	2007	2006
Defined benefit pension liability adjustments	**$ (465)**	(665)
Foreign currency translation adjustments	**5,033**	1,958
Deferred net hedging loss	**(8)**	(4)
Accumulated other comprehensive income	**$4,560**	1,289

Note 26 — Cash Flow Information

	Millions of Dollars		
	2007	2006	2005
Non-Cash 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 non-cash assets and liabilities	2,428	—	—
Increase in properties, plants and equipment (PP&E) resulting from our payment obligations to acquire an ownership interest in producing properties in Libya	—	—	732
Increase in PP&E related to an increase in asset retirement obligations	919	464	511
Cash Payments			
Interest	$ 1,040	958	500
Income taxes	11,330	13,050	8,507

Note 27 — Other Financial Information

	Millions of Dollars Except Per Share Amounts		
	2007	2006	2005
Interest and Debt Expense			
Incurred			
Debt	$ 1,369	1,409	807
Other	449	136	85
	1,818	1,545	892
Capitalized	(565)	(458)	(395)
Expensed	$ 1,253	1,087	497
Other Income			
Interest income	$ 342	165	127
Gain on asset dispositions	1,348	116	278
Business interruption insurance recoveries*	52	239	—
Other	229	165	60
	$ 1,971	685	465

**Primarily related to 2005 hurricanes in the Gulf of Mexico and southern United States.*

Research and Development Expenditures — expensed	$ 160	117	125
Advertising Expenses	$ 84	87	84
Shipping and Handling Costs*	$ 1,493	1,415	1,265

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

Cash Dividends paid per common share	$ 1.64	1.44	1.18
Foreign Currency Transaction Gains (Losses) — after-tax			
E&P	$ 216	(44)	7
Midstream	(2)	—	7
R&M	(13)	60	(52)
LUKOIL Investment	5	—	(1)
Chemicals	—	—	—
Emerging Businesses	1	1	(1)
Corporate and Other	(120)	65	(42)
	$ 87	82	(82)

Note 28 — Related Party Transactions

Significant transactions with related parties were:

	Millions of Dollars		
	2007	2006*	2005*
Operating revenues (a)	$10,949	8,808	7,719
Purchases (b)**	15,722	7,072	6,089
Operating expenses and selling, general and administrative expenses (c)	416	386	380
Net interest expense (d)	99	(13)	30

**Restated to include additional related party transactions.*
***The increase in 2007 is primarily due to purchases from the WRB Refining 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. We also sold various international marketing companies to LUKOIL in the second quarter of 2007. 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 Refining. 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 and 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 10 — Investments, Loans and Long-Term Receivables, for additional information on loans to affiliated companies.

Note 29 — Segment Disclosures and Related Information

We have organized our reporting structure based on the grouping of similar products and services, resulting in six operating segments:

1) E&P — This segment primarily explores for, produces, transports and markets crude oil, natural gas and natural gas liquids on a worldwide basis. At December 31, 2007, our E&P operations were producing in the United States, Norway, the United Kingdom, the Netherlands, Canada, Nigeria, Ecuador, Argentina, offshore Timor-Leste in the Timor Sea, Australia, China, Indonesia, Algeria, Libya, Vietnam, and Russia. The E&P segment's U.S. and international operations are disclosed separately for reporting purposes.
2) Midstream — This segment gathers, processes and markets natural gas produced by ConocoPhillips and others, and fractionates and markets natural gas liquids, primarily in the United States and Trinidad. The Midstream segment primarily consists of our 50 percent equity investment in DCP Midstream.
3) R&M — This segment purchases, refines, markets and transports crude oil and petroleum products, mainly in the United States, Europe and Asia. At December 31, 2007, 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 LUKOIL, an international, integrated oil and gas company headquartered in Russia. At December 31, 2007, our ownership interest was 20 percent based on issued shares, and 20.6 percent based on estimated shares outstanding. See Note 10—Investments, Loans and Long-Term Receivables, for additional information.
5) Chemicals — This segment manufactures and markets petrochemicals and plastics on a worldwide basis. The Chemicals segment consists of our 50 percent equity investment in CPChem.
6) Emerging Businesses — 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 other items, such as carbon-to-liquids, technology solutions, and alternative energy and programs, such as advanced hydrocarbon processes, energy conversion technologies, new petroleum-based products, and renewable fuels.

Corporate and Other includes general corporate overhead, most interest income and expense, discontinued operations, restructuring charges, and various other corporate activities. Corporate assets include all cash and cash equivalents.

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

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

Analysis of Results by Operating Segment

	Millions of Dollars		
	2007	2006	2005
Sales and Other Operating Revenues			
E&P			
United States	**$ 36,974**	35,335	35,159
International	**24,617**	28,111	21,692
Intersegment eliminations — U.S.	**(6,096)**	(5,438)	(4,075)
Intersegment eliminations — international	**(7,341)**	(7,842)	(4,251)
E&P	**48,154**	50,166	48,525
Midstream			
Total sales	**5,106**	4,461	4,041
Intersegment eliminations	**(245)**	(1,037)	(955)
Midstream	**4,861**	3,424	3,086
R&M			
United States	**96,154**	95,314	97,251
International	**38,598**	35,439	30,633
Intersegment eliminations — U.S.	**(540)**	(855)	(593)
Intersegment eliminations — international	**(11)**	(21)	(11)
R&M	**134,201**	129,877	127,280
LUKOIL Investment	**—**	—	—
Chemicals	**10**	13	14
Emerging Businesses*			
Total sales	**656**	675	618
Intersegment eliminations	**(458)**	(515)	(426)
Emerging Businesses	**198**	160	192
Corporate and Other	**13**	10	13
Other adjustments*	**—**	—	332
Consolidated sales and other operating revenues	**$187,437**	183,650	179,442

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

	2007	2006	2005
Depreciation, Depletion, Amortization and Impairments			
E&P			
United States	**$ 3,328**	2,901	1,402
International	**9,121**	3,445	1,914
Total E&P	**12,449**	6,346	3,316
Midstream	**14**	29	61
R&M			
United States	**609**	1,014	633
International	**139**	458	193
Total R&M	**748**	1,472	826
LUKOIL Investment	**—**	—	—
Chemicals	**—**	—	—
Emerging Businesses	**39**	58	32
Corporate and Other	**78**	62	60
Consolidated depreciation, depletion, amortization and impairments	**$ 13,328**	7,967	4,295

	Millions of Dollars		
	2007	2006	2005
Equity in Earnings of Affiliates			
E&P			
United States	**$ 11**	20	19
International	**302**	782	825
Total E&P	**313**	802	844
Midstream	**599**	618	829
R&M			
United States	**1,710**	466	388
International	**240**	151	227
Total R&M	**1,950**	617	615
LUKOIL Investment	**1,875**	1,481	756
Chemicals	**350**	665	413
Emerging Businesses	**—**	5	—
Corporate and Other	**—**	—	—
Consolidated equity in earnings of affiliates	**$ 5,087**	4,188	3,457
Income Taxes			
E&P			
United States	**$ 2,231**	2,545	2,349
International	**6,372**	7,584	5,145
Total E&P	**8,603**	10,129	7,494
Midstream	**237**	248	214
R&M			
United States	**2,571**	2,334	2,124
International	**113**	218	212
Total R&M	**2,684**	2,552	2,336
LUKOIL Investment	**45**	37	25
Chemicals	**(13)**	171	93
Emerging Businesses	**(33)**	(2)	(18)
Corporate and Other	**(142)**	(352)	(237)
Consolidated income taxes	**$ 11,381**	12,783	9,907
Net Income (Loss)			
E&P			
United States	**$ 4,248**	4,348	4,288
International	**367**	5,500	4,142
Total E&P	**4,615**	9,848	8,430
Midstream	**453**	476	688
R&M			
United States	**4,615**	3,915	3,329
International	**1,308**	566	844
Total R&M	**5,923**	4,481	4,173
LUKOIL Investment	**1,818**	1,425	714
Chemicals	**359**	492	323
Emerging Businesses	**(8)**	15	(21)
Corporate and Other	**(1,269)**	(1,187)	(778)
Consolidated net income	**$ 11,891**	15,550	13,529
Investments In and Advances To Affiliates			
E&P			
United States	**$ 1,059**	690	336
International	**12,055**	4,346	3,789
Total E&P	**13,114**	5,036	4,125
Midstream	**1,178**	1,319	1,446
R&M			
United States	**3,500**	698	662
International	**1,091**	948	819
Total R&M	**4,591**	1,646	1,481
LUKOIL Investment	**11,162**	9,564	5,549
Chemicals	**2,203**	2,255	2,158
Emerging Businesses	**79**	—	—
Corporate and Other	**—**	—	18
Consolidated investments in and advances to affiliates*	**$ 32,327**	19,820	14,777
**Includes amounts classified as held for sale:*	***$ 48***	*158*	—

	Millions of Dollars		
	2007	2006	2005
Total Assets			
E&P			
United States	**$ 35,160**	35,523	18,434
International	**59,412**	48,143	31,662
Goodwill	**25,569**	27,712	11,423
Total E&P	**120,141**	111,378	61,519
Midstream	**2,016**	2,045	2,109
R&M			
United States	**24,336**	22,936	20,693
International	**9,766**	9,135	6,096
Goodwill	**3,767**	3,776	3,900
Total R&M	**37,869**	35,847	30,689
LUKOIL Investment	**11,164**	9,564	5,549
Chemicals	**2,225**	2,379	2,324
Emerging Businesses	**1,230**	977	858
Corporate and Other	**3,112**	2,591	3,951
Consolidated total assets	**$177,757**	164,781	106,999
Capital Expenditures and Investments*			
E&P			
United States	**$ 3,788**	2,828	1,637
International	**6,147**	6,685	5,047
Total E&P	**9,935**	9,513	6,684
Midstream	**5**	4	839
R&M			
United States	**1,146**	1,597	1,537
International	**240**	1,419	201
Total R&M	**1,386**	3,016	1,738
LUKOIL Investment	**—**	2,715	2,160
Chemicals	**—**	—	—
Emerging Businesses	**257**	83	5
Corporate and Other	**208**	265	194
Consolidated capital expenditures and investments	**$ 11,791**	15,596	11,620

**Net of cash acquired.*

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

	Millions of Dollars		
	2007	2006	2005
Interest income*	**$ 246**	106	113
Interest and debt expense**	**1,066**	1,087	497
**In addition, the E&P segment had interest income of:*	***$ 96***	*57*	*12*
***In addition, the E&P segment had interest expense of:*	***187***	—	—

Geographic Information

	Millions of Dollars						
	United States	Norway	United Kingdom	Canada	Russia	Other Foreign Countries	Worldwide Consolidated
2007							
Sales and Other Operating Revenues*	**$ 131,433**	**2,479**	**20,680**	**4,727**	**—**	**28,118**	**187,437**
Long-Lived Assets**	**$ 50,714**	**6,180**	**7,995**	**24,758**	**13,359**	**18,324**	**121,330**
2006							
Sales and Other Operating Revenues*	$ 127,869	2,480	19,510	5,554	—	28,237	183,650
Long-Lived Assets**	$ 48,418	4,982	7,755	14,831	10,886	19,149	106,021
2005							
Sales and Other Operating Revenues*	$ 130,874	3,280	19,043	5,676	—	20,569	179,442
Long-Lived Assets**	$ 33,161	4,380	5,564	5,328	6,342	14,671	69,446

**Sales and other operating revenues are attributable to countries based on the location of the operations generating the revenues.*
***Defined as net properties, plants and equipment plus investments in and advances to affiliated companies.*

Note 30 — New Accounting Standards

In September 2006, the FASB issued SFAS No. 157, "Fair Value Measurements." This Statement defines fair value, establishes a framework for its measurement and expands disclosures about fair value measurements. We use fair value measurements to measure, among other items, purchased assets and investments, derivative contracts and financial guarantees. We also use them to assess impairment of properties, plants and equipment, intangible assets and goodwill. The Statement does not apply to share-based payment transactions and inventory pricing. In February 2008, the FASB issued a FASB Staff Position (FSP) on Statement No. 157 that permits a one-year delay of the effective date for all non-financial assets and non-financial liabilities, except those that are recognized or disclosed at fair value in the financial statements on a recurring basis (at least annually). We will adopt this Statement effective January 1, 2008, with the exceptions allowed under the FSP described above and do not expect any significant impact to our consolidated financial statements, other than additional disclosures.

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 an entity to choose to measure financial instruments and certain other items similar to financial instruments at fair value, with all subsequent changes in fair value for the financial instrument 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 will adopt this Statement effective January 1, 2008, and do not expect any significant impact to our consolidated financial statements.

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. This Statement applies prospectively to business combinations for which the acquisition date is on or after January 1, 2009. However, 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 the prior business combination accounting starting January 1, 2009. We are currently evaluating the changes provided in this Statement.

Also in December 2007, the FASB issued SFAS No. 160, "Noncontrolling Interests in Consolidated Financial Statements — an amendment of ARB No. 51," which changes the classification of non-controlling interests, sometimes called a minority interest, in the consolidated financial statements. Additionally, this Statement establishes a single method of accounting for changes in a parent company's ownership interest that do not result in deconsolidation and requires a parent company to recognize a gain or loss when a subsidiary is deconsolidated. 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. We are currently evaluating the impact on our consolidated financial statements.

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 segment, as well as in our LUKOIL Investment segment. As a result, amounts reported as Equity Affiliates in Oil and Gas Operations may differ from those shown in the individual segment disclosures reported elsewhere in this report. The data included for the LUKOIL Investment segment reflects the company's estimated share of OAO LUKOIL's (LUKOIL) amounts. Because LUKOIL's accounting cycle close and preparation of U.S. GAAP financial statements occur subsequent to our reporting deadline, our equity share of financial information and statistics for our LUKOIL investment are estimated based on current market indicators, publicly available LUKOIL operating results, and other objective data. Once the difference between actual and estimated results is known, an adjustment is recorded. Our estimated year-end 2007 reserves related to our equity investment in LUKOIL are based on LUKOIL's year-end 2007 reserve estimates and include adjustments to conform them to ConocoPhillips' reserve policy.

The information about our proportionate share of equity affiliates is necessary for a full understanding of our operations because equity affiliate operations are an integral part of the overall success of our oil and gas operations.

Our proved reserves include estimated quantities related to production sharing contracts (PSCs), which are reported under the "economic interest" method and are subject to fluctuations in prices of crude oil, natural gas and natural gas liquids; recoverable operating expenses; and capital costs. If costs remain stable, reserve quantities attributable to recovery of costs will change inversely to changes in commodity prices. For example, if prices go up then our applicable reserve quantities would decline. At December 31, 2007, approximately 12 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 (U.S.), Canada, Europe (primarily Norway and the United Kingdom), Asia Pacific, Middle East and Africa, Russia and Caspian, and Other Areas (primarily South America). In these supplemental oil and gas disclosures, where we use equity accounting for operations that have proved reserves, these operations are shown separately and designated as Equity Affiliates, and include Canada, Middle East and Africa, Russia and Caspian, and Other Areas. Canada includes our share of FCCL Oil Sands Partnership (FCCL). 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.

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

All of our proved crude oil, natural gas and natural gas liquids reserves held by consolidated companies have been estimated by ConocoPhillips. Our policy with respect to equity affiliates is either to estimate the proved reserve quantities ourselves (applicable to those situations where we have a substantial engineering presence), or to rely on estimates prepared by the equity affiliate, and perform a reasonableness review of those assessments. Of the proved reserves attributable to equity affiliates at year-end 2007, 38 percent was based on assessments of the available data performed by ConocoPhillips. The remaining 62 percent, reflecting our equity interest in LUKOIL, was based on estimates prepared by the equity affiliate. These equity-affiliate-prepared estimates are reviewed by ConocoPhillips and adjusted to comply with our internal reserves governance policies.

In addition, during 2007, approximately 43 percent of our year-end 2006 E&P proved reserves were reviewed by an outside unrelated third-party petroleum engineering consulting firm. At the present time, we plan to continue to have an outside firm review a pro rata portion of a similar percentage of our reserve base over the next two years.

Engineering estimates of the quantities of recoverable oil and gas reserves in oil and gas fields and in-place crude bitumen volumes in oil sand mining operations are inherently imprecise. See the "Critical Accounting 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 2004	1,536	170	1,706	47	851	255	127	181	—	3,167	1,982
Revisions	31	6	37	4	34	7	(21)	(11)	—	50	6
Improved recovery	15	1	16	—	—	—	—	—	—	16	—
Purchases	—	3	3	—	—	—	238	20	—	261	515
Extensions and discoveries	31	13	44	1	17	49	4	—	17	132	60
Production	(108)	(21)	(129)	(8)	(94)	(37)	(20)	—	—	(288)	(130)
Sales	—	(2)	(2)	—	—	—	—	—	—	(2)	(3)
End of 2005	1,505	170	1,675	44	808	274	328	190	17	3,336	2,430
Revisions	(118)	(11)	(129)	58	(65)	(12)	(18)	(74)	2	(238)	(35)
Improved recovery	13	1	14	—	5	63	—	—	—	82	—
Purchases	—	181	181	16	—	13	42	—	17	269	393
Extensions and discoveries	53	9	62	4	6	8	3	—	—	83	74
Production	(97)	(37)	(134)	(9)	(90)	(39)	(39)	—	(3)	(314)	(171)
Sales	—	(18)	(18)	—	—	—	—	—	—	(18)	(1)
End of 2006	1,356	295	1,651	113	664	307	316	116	33	3,200	2,690
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
Equity affiliates											
End of 2004	—	—	—	—	—	—	—	800	1,182	—	1,982
End of 2005	—	—	—	—	—	—	46	1,295	1,089	—	2,430
End of 2006	—	—	—	—	—	—	60	1,607	1,023	—	2,690
End of 2007	—	—	—	623	—	—	70	1,705	—	—	2,398
Developed											
Consolidated operations											
End of 2004	1,415	148	1,563	46	429	207	121	—	—	2,366	—
End of 2005	1,359	158	1,517	42	409	202	326	—	—	2,496	—
End of 2006	1,254	281	1,535	50	359	181	292	—	13	2,430	—
End of 2007	1,238	281	1,519	51	337	146	259	—	9	2,321	—
Equity affiliates											
End of 2004	—	—	—	—	—	—	—	624	491	—	1,115
End of 2005	—	—	—	—	—	—	—	1,013	472	—	1,485
End of 2006	—	—	—	—	—	—	—	1,293	369	—	1,662
End of 2007	—	—	—	45	—	—	—	1,336	—	—	1,381

Notable changes in proved crude oil reserves in the three years ending December 31, 2007, included:

- *Revisions:* 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 March 2006. In 2006 and 2005 for our equity affiliate operations, purchases were mainly attributable to acquiring additional interests in LUKOIL. In 2005, purchases in the Middle East and Africa were attributable to our re-entry into Libya.
- *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 221 million barrels at the end of 2007. For internal management purposes, we view these mining reserves and their development as part of our total exploration and production operations. However, SEC regulations define these reserves as mining related. Therefore, they are not included in our tabular presentation of proved crude oil, natural gas and NGL reserves. These oil sands 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 2004	3,344	4,234	7,578	975	3,285	3,773	1,104	119	—	16,834	862
Revisions	260	(43)	217	72	83	(20)	—	(3)	—	349	51
Improved recovery	—	1	1	—	—	—	—	—	—	1	—
Purchases	7	163	170	—	1	8	—	13	—	192	453
Extensions and discoveries	5	270	275	78	79	85	2	—	5	524	1,212
Production	(144)	(449)	(593)	(155)	(386)	(146)	(45)	—	—	(1,325)	(30)
Sales	—	(62)	(62)	—	—	—	—	—	—	(62)	—
End of 2005	3,472	4,114	7,586	970	3,062	3,700	1,061	129	5	16,513	2,548
Revisions	43	(87)	(44)	(123)	(293)	71	(64)	(31)	(39)	(523)	(310)
Improved recovery	—	4	4	—	1	—	—	—	—	5	—
Purchases	6	5,258	5,264	2,466	432	25	94	—	129	8,410	325
Extensions and discoveries	23	551	574	353	64	6	58	—	—	1,055	925
Production	(130)	(770)	(900)	(356)	(414)	(233)	(62)	—	(6)	(1,971)	(99)
Sales	—	(43)	(43)	—	—	—	—	—	—	(43)	—
End of 2006	3,414	9,027	12,441	3,310	2,852	3,569	1,087	98	89	23,446	3,389
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
Equity affiliates											
End of 2004	—	—	—	—	—	—	—	661	201	—	862
End of 2005	—	—	—	—	—	—	1,063	1,197	288	—	2,548
End of 2006	—	—	—	—	—	—	1,573	1,429	387	—	3,389
End of 2007	—	—	—	—	—	—	1,925	1,014	—	—	2,939
Developed											
Consolidated operations											
End of 2004	3,194	3,989	7,183	934	2,467	1,520	522	—	—	12,626	—
End of 2005	3,316	3,966	7,282	918	2,393	2,600	1,060	—	—	14,253	—
End of 2006	3,336	7,484	10,820	2,672	2,314	3,105	1,029	—	24	19,964	—
End of 2007	3,344	7,417	10,761	2,328	2,177	2,857	963	—	26	19,112	—
Equity affiliates											
End of 2004	—	—	—	—	—	—	—	207	118	—	325
End of 2005	—	—	—	—	—	—	—	581	155	—	736
End of 2006	—	—	—	—	—	—	—	655	173	—	828
End of 2007	—	—	—	—	—	—	—	698	—	—	698

Natural gas production may differ from gas production (delivered for sale) in our statistics disclosure, primarily because the quantities above include gas consumed at the lease, but omit the gas equivalent of liquids extracted at any of our owned, equity-affiliate, or third-party processing plants or facilities.

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, 2007, included:

- *Purchases:* 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. In 2005, extensions and discoveries for our equity affiliate operations were primarily in Qatar.

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 2004	153	88	241	26	48	71	4	—	—	390	—
Revisions	—	17	17	1	6	4	—	—	—	28	—
Improved recovery	—	—	—	—	—	—	—	—	—	—	—
Purchases	—	8	8	—	—	—	—	—	—	8	—
Extensions and discoveries	—	5	5	—	1	2	—	—	—	8	21
Production	(7)	(9)	(16)	(3)	(5)	(6)	(1)	—	—	(31)	—
Sales	—	(1)	(1)	—	—	—	—	—	—	(1)	—
End of 2005	146	108	254	24	50	71	3	—	—	402	21
Revisions	(1)	24	23	1	(4)	(1)	(1)	—	—	18	—
Improved recovery	—	—	—	—	—	—	—	—	—	—	—
Purchases	—	328	328	56	—	—	—	—	—	384	—
Extensions and discoveries	—	14	14	7	—	—	—	—	—	21	11
Production	(6)	(22)	(28)	(9)	(5)	(7)	—	—	—	(49)	—
Sales	—	(2)	(2)	—	—	—	—	—	—	(2)	—
End of 2006	139	450	589	79	41	63	2	—	—	774	32
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
Equity affiliates											
End of 2004	—	—	—	—	—	—	—	—	—	—	—
End of 2005	—	—	—	—	—	—	21	—	—	—	21
End of 2006	—	—	—	—	—	—	32	—	—	—	32
End of 2007	—	—	—	—	—	—	39	20	—	—	59
Developed											
Consolidated operations											
End of 2004	153	82	235	25	34	71	4	—	—	369	—
End of 2005	146	106	252	23	31	64	2	—	—	372	—
End of 2006	139	346	485	64	28	56	2	—	—	635	—
End of 2007	133	343	476	53	33	54	1	—	—	617	—
Equity affiliates											
End of 2004	—	—	—	—	—	—	—	—	—	—	—
End of 2005	—	—	—	—	—	—	—	—	—	—	—
End of 2006	—	—	—	—	—	—	—	—	—	—	—
End of 2007	—	—	—	—	—	—	—	18	—	—	18

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, 2007, included:

- *Purchases:* In 2006 for our consolidated operations, purchases were related to our acquisition of Burlington Resources.

■ Results of Operations

Years Ended December 31	Alaska	Lower 48	Total U.S.	Canada	Europe	Asia Pacific	Middle East and Africa	Russia and Caspian	Other Areas	Total	Equity Affiliates
	Millions of Dollars										
	Consolidated Operations										
2007											
Sales	$4,659	5,422	10,081	3,406	5,701	3,383	1,038	—	240	23,849	5,212
Transfers	2,344	2,986	5,330	—	2,729	267	1,157	—	—	9,483	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
Impairment — expropriated assets	—	—	—	—	—	—	—	—	4,588	4,588	—
Property impairments	28	43	71	27	188	26	—	—	155	467	—
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)	(4,752)	12,508	2,676
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)	(4,753)	3,837	1,832
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)	(4,556)	4,387	2,046
Results of operations for producing activities of equity affiliates	$ —	—	—	98	—	—	(5)	1,554	185	—	1,832
2006											
Sales*	$4,491	4,881	9,372	2,951	5,950	3,493	1,743	—	140	23,649	5,161
Transfers*	2,023	2,550	4,573	—	2,954	271	764	—	—	8,562	2,821
Other revenues	2	56	58	145	14	(8)	127	—	4	340	108
Total revenues	6,516	7,487	14,003	3,096	8,918	3,756	2,634	—	144	32,551	8,090
Production costs excluding taxes	708	893	1,601	706	814	324	215	—	27	3,687	739
Taxes other than income taxes	914	554	1,468	52	37	91	10	1	30	1,689	3,444
Exploration expenses	105	222	327	246	73	121	44	32	17	860	46
Depreciation, depletion and amortization	460	2,272	2,732	1,155	1,200	512	220	1	21	5,841	461
Property impairments	—	15	15	131	—	10	—	—	19	175	—
Transportation costs	610	555	1,165	104	316	89	18	—	10	1,702	420
Other related expenses	11	44	55	15	87	18	38	43	28	284	52
Accretion	34	36	70	39	97	8	2	—	—	216	6
	3,674	2,896	6,570	648	6,294	2,583	2,087	(77)	(8)	18,097	2,922
Provision for income taxes	1,409	1,064	2,473	(193)	4,578	1,061	1,931	(13)	(7)	9,830	891
Results of operations for producing activities	2,265	1,832	4,097	841	1,716	1,522	156	(64)	(1)	8,267	2,031
Other earnings	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 Alaska, Lower 48, Asia Pacific, and the Middle East and Africa were reclassified. Total revenue was unchanged.*

***Restated to increase Alaska and reduce Lower 48 by $14 million related to overhead previously aligned with Alaska.*

	Millions of Dollars										
	Consolidated Operations										
	Alaska	Lower 48	Total U.S.	Canada	Europe	Asia Pacific	Middle East and Africa	Russia and Caspian	Other Areas	Total	Equity Affiliates
2005											
Sales*	$4,102	3,385	7,487	1,642	5,142	2,795	423	—	—	17,489	3,470
Transfers*	1,997	1,206	3,203	—	2,207	26	640	—	—	6,076	1,458
Other revenues	2	168	170	40	(253)	11	4	—	—	(28)	38
Total revenues	6,101	4,759	10,860	1,682	7,096	2,832	1,067	—	—	23,537	4,966
Production costs excluding taxes	488	492	980	316	612	274	115	—	—	2,297	452
Taxes other than income taxes	537	311	848	33	41	26	18	1	1	968	1,635
Exploration expenses	120	66	186	147	87	139	69	33	8	669	56
Depreciation, depletion and amortization	443	848	1,291	399	1,074	329	53	—	—	3,146	288
Property impairments	—	1	1	13	(10)	—	—	—	—	4	—
Transportation costs	665	350	1,015	53	296	64	5	—	—	1,433	255
Other related expenses	67	48	115	(12)	28	38	32	35	17	253	26
Accretion	29	19	48	16	84	7	2	—	—	157	1
	3,752	2,624	6,376	717	4,884	1,955	773	(69)	(26)	14,610	2,253
Provision for income taxes	1,342	900	2,242	228	3,311	747	759	(6)	(13)	7,268	673
Results of operations for producing activities	2,410	1,724	4,134	489	1,573	1,208	14	(63)	(13)	7,342	1,580
Other earnings	141	15	156	93	64	7	(28)	(2)	26	316	(90)
Cumulative effect of accounting change	1	(3)	(2)	—	(2)	—	—	—	—	(4)	—
Net income (loss)	$2,552	1,736	4,288	582	1,635	1,215	(14)	(65)	13	7,654	1,490
Results of operations for producing activities of equity affiliates	$ —	—	—	—	—	—	(11)	773	818	—	1,580

**Certain amounts in Alaska were reclassified. Total revenues were unchanged.*

- Results of operations for producing activities consist of all the activities within the E&P organization and producing activities within the LUKOIL Investment segment, except for pipeline and marine operations, liquefied natural gas operations, a Canadian Syncrude operation, and crude oil and gas marketing activities, which are included in other earnings. Also excluded are our Midstream segment, downstream petroleum and chemical activities, as well as general corporate administrative expenses and interest.
- Transfers are valued at prices that approximate market.
- Other revenues include gains and losses from asset sales, certain amounts resulting from the purchase and sale of hydrocarbons, and other miscellaneous income. Also included in 2005 were losses of approximately $282 million for the mark-to-market valuation of certain U.K. gas contracts.
- Production costs are those incurred to operate and maintain wells and related equipment and facilities used to produce petroleum liquids and natural gas. These costs also include depreciation of support equipment and administrative expenses related to the production activity.
- Taxes other than income taxes include production, property and other non-income taxes.
- Exploration expenses include dry hole, leasehold impairment, geological and geophysical expenses, the cost of retaining undeveloped leaseholds, and depreciation of support equipment and administrative expenses related to the exploration activity.
- Depreciation, depletion and amortization (DD&A) in Results of Operations differs from that shown for total E&P in Note 29 — Segment Disclosures and Related Information, in the Notes to Consolidated Financial Statements, mainly due to depreciation of support equipment being reclassified to production or exploration expenses, as applicable, in Results of Operations. In addition, other earnings include certain E&P activities, including their related DD&A charges.
- Transportation costs include costs to transport our produced oil, natural gas or natural gas liquids to their points of sale, as well as processing fees paid to process natural gas to natural gas liquids. The profit element of transportation operations in which we have an ownership interest are deemed to be outside the oil and gas producing activity. The net income of the transportation operations is included in other earnings.
- Other related expenses include foreign currency gains and losses, and other miscellaneous expenses.
- The provision for income taxes is computed by adjusting each country's income before income taxes for permanent differences related to the oil and gas producing activities that are reflected in our consolidated income tax expense for the period, multiplying the result by the country's statutory tax rate and adjusting for applicable tax credits. Included in 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	2007	2006	2005
	Thousands of Barrels Daily		
Crude Oil			
Consolidated operations			
Alaska	**261**	263	294
Lower 48	**102**	104	59
United States	**363**	367	353
Canada	**19**	25	23
Europe	**210**	245	257
Asia Pacific	**87**	106	100
Middle East and Africa	**81**	106	53
Other areas	**10**	7	—
Total consolidated	**770**	856	786
Equity affiliates			
Canada	**27**	—	—
Russia and Caspian	**416**	375	250
Other areas	**42**	101	106
Total equity affiliates	**485**	476	356
Natural Gas Liquids*			
Consolidated operations			
Alaska	**19**	17	20
Lower 48	**79**	62	30
United States	**98**	79	50
Canada	**27**	25	10
Europe	**14**	13	13
Asia Pacific	**14**	18	16
Middle East and Africa	**2**	1	2
Total consolidated	**155**	136	91

**Represents amounts extracted attributable to E&P operations (see natural gas liquids reserves for further discussion). Includes for 2007, 2006 and 2005, 14,000, 11,000, and 9,000 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.*

	2007	2006	2005
	Millions of Cubic Feet Daily		
Natural Gas*			
Consolidated operations			
Alaska	**110**	145	169
Lower 48	**2,182**	2,028	1,212
United States	**2,292**	2,173	1,381
Canada	**1,106**	983	425
Europe	**961**	1,065	1,023
Asia Pacific	**579**	582	350
Middle East and Africa	**125**	142	84
Other areas	**19**	16	—
Total consolidated	**5,082**	4,961	3,263
Equity affiliates			
Russia and Caspian	**256**	244	67
Other areas	**5**	9	7
Total equity affiliates	**261**	253	74

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

Average Sales Price	2007	2006	2005
Crude Oil			
Per Barrel			
Consolidated operations			
Alaska	**$69.75**	62.66	52.24
Lower 48	**63.49**	57.04	45.24
United States	**68.00**	61.09	51.09
Canada	**61.77**	54.25	44.70
Europe	**71.81**	64.05	53.16
Asia Pacific	**70.23**	61.93	51.34
Middle East and Africa	**72.18**	66.59	52.93
Other areas	**60.84**	50.63	—
Total international	**70.79**	63.38	52.27
Total consolidated	**69.47**	62.39	51.74
Equity affiliates			
Canada	**37.94**	—	—
Russia and Caspian	**50.00**	41.61	37.39
Other areas	**47.46**	46.40	38.08
Total equity affiliates	**49.13**	42.66	37.60
Natural Gas Liquids			
Per Barrel			
Consolidated operations			
Alaska	**$71.85**	61.06	51.30
Lower 48	**44.43**	38.10	36.43
United States	**46.00**	40.35	40.40
Canada	**50.85**	45.62	42.20
Europe	**45.72**	38.78	31.25
Asia Pacific	**53.19**	43.95	40.11
Middle East and Africa	**8.31**	8.15	7.39
Total international	**48.80**	42.89	36.25
Total consolidated	**47.13**	41.50	38.32
Natural Gas			
Per Thousand Cubic Feet			
Consolidated operations			
Alaska	**$ 3.68**	3.59	2.75
Lower 48	**5.99**	6.14	7.28
United States	**5.98**	6.11	7.12
Canada	**6.09**	5.67	7.25
Europe	**7.87**	7.78	5.77
Asia Pacific	**6.37**	5.91	5.24
Middle East and Africa	**.80**	.70	.67
Other areas	**1.18**	1.31	—
Total international	**6.51**	6.27	5.78
Total consolidated	**6.26**	6.20	6.32
Equity affiliates			
Russia and Caspian	**1.02**	.57	.48
Other areas	**.30**	.30	.26
Total equity affiliates	**1.01**	.57	.46
Average Production Costs			
Per Barrel of Oil Equivalent			
Consolidated operations			
Alaska	**$ 7.12**	6.38	3.91
Lower 48	**6.20**	4.85	4.63
United States	**6.52**	5.43	4.24
Canada	**10.40**	9.05	8.34
Europe	**7.34**	5.12	3.81
Asia Pacific	**5.69**	4.02	4.31
Middle East and Africa	**6.62**	4.51	4.57
Other areas	**8.53**	7.65	—
Total international	**7.68**	5.65	4.58
Total consolidated	**7.13**	5.55	4.43
Equity affiliates			
Canada	**13.32**	—	—
Russia and Caspian	**4.04**	3.53	2.69
Other areas	**6.24**	5.42	5.01
Total equity affiliates	**4.70**	3.91	3.36

Taxes Other Than Income Taxes Per Barrel of Oil Equivalent	2007	2006	2005
Consolidated operations			
Alaska	**$ 15.27**	8.23	4.30
Lower 48	**3.16**	3.01	2.93
United States	**7.45**	4.98	3.67
Canada	**.83**	.67	.87
Europe	**.32**	.23	.26
Asia Pacific	**1.79**	1.13	.41
Middle East and Africa	**.47**	.21	.71
Other areas	**20.39**	8.50	—
Total international	**1.07**	.60	.42
Total consolidated	**4.10**	2.54	1.87
Equity affiliates			
Canada	**.21**	—	—
Russia and Caspian	**20.89**	21.40	17.12
Other areas	**11.21**	5.28	.06
Total equity affiliates	**19.05**	18.21	12.16

Depreciation, Depletion and Amortization Per Barrel of Oil Equivalent	2007	2006	2005
Consolidated operations			
Alaska	**$ 5.35**	4.14	3.55
Lower 48	**12.87**	12.35	7.98
United States	**10.21**	9.26	5.59
Canada	**19.76**	14.80	10.53
Europe	**9.94**	7.55	6.68
Asia Pacific	**8.43**	6.35	5.17
Middle East and Africa	**5.38**	4.61	2.10
Other areas	—	5.95	—
Total international	**11.40**	8.43	6.45
Total consolidated	**10.84**	8.80	6.07
Equity affiliates			
Canada	**6.82**	—	—
Russia and Caspian	**2.53**	2.04	1.55
Other areas	**3.88**	4.04	3.58
Total equity affiliates	**2.86**	2.43	2.14

Acreage at December 31, 2007	Thousands of Acres			
	Developed		Undeveloped	
	Gross	Net	Gross	Net
Consolidated operations				
Alaska	646	327	2,475	1,572
Lower 48	7,666	5,301	13,965	9,917
United States	8,312	5,628	16,440	11,489
Canada	7,002	4,328	14,074	9,292
Europe	1,373	342	4,454	1,429
Asia Pacific	4,214	1,818	28,367	18,588
Middle East and Africa	2,466	449	13,395	2,694
Russia and Caspian	—	—	1,379	128
Other areas	1,356	573	13,071	10,444
Total consolidated	24,723	13,138	91,180	54,064
Equity affiliates				
Canada	57	23	483	186
Middle East and Africa	—	—	76	11
Russia and Caspian	385	119	2,898	994
Other areas	—	—	—	—
Total equity affiliates*	442	142	3,457	1,191

**Excludes LUKOIL.*

Net Wells Completed[1]	Productive			Dry		
	2007	2006	2005	**2007**	2006	2005
Exploratory[2]						
Consolidated operations						
Alaska	**3**	—	—	**1**	1	5
Lower 48	**71**	27	23	**9**	9	5
United States	**74**	27	23	**10**	10	10
Canada	**50**	8	26	**17**	7	7
Europe	**1**	1	1	**1**	1	*
Asia Pacific	**4**	2	7	**1**	2	3
Middle East and Africa	—	1	—	**1**	1	2
Russia and Caspian	—	—	—	*	—	*
Other areas	—	1	1	—	*	—
Total consolidated	**129**	40	58	**30**	21	22
Equity affiliates						
Canada	—	—	—	—	—	—
Middle East and Africa	—	*	*	—	—	—
Russia and Caspian	—	—	—	—	1	—
Other areas	—	—	—	—	—	—
Total equity affiliates[3]	—	*	*	—	1	—
Includes step-out wells of:	***99***	*37*	*42*	***18***	*11*	*7*
Development						
Consolidated operations						
Alaska	**46**	30	31	—	1	—
Lower 48	**686**	659	297	**7**	3	9
United States	**732**	689	328	**7**	4	9
Canada	**348**	675	425	**1**	8	2
Europe	**10**	10	19	—	—	—
Asia Pacific	**17**	15	17	—	—	—
Middle East and Africa	**7**	7	6	*	—	—
Russia and Caspian	*	*	—	—	—	—
Other areas	**5**	11	—	—	—	—
Total consolidated	**1,119**	1,407	795	**8**	12	11
Equity affiliates						
Canada	**70**	—	—	**1**	—	—
Middle East and Africa	—	—	—	—	—	—
Russia and Caspian	**2**	2	1	—	1	—
Other areas	—	15	28	—	—	1
Total equity affiliates[3]	**72**	17	29	**1**	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.*

Wells at Year-End 2007	In Progress[1]		Productive[2]			
			Oil		Gas	
	Gross	Net	Gross	Net	Gross	Net
Consolidated operations						
Alaska	22	12	1,790	810	27	18
Lower 48	280	233	12,498	4,595	24,742	16,135
United States	302	245	14,288	5,405	24,769	16,153
Canada	147[3]	87[3]	1,648	913	10,773	6,412
Europe	59	11	556	99	344	118
Asia Pacific	168	79	335	124	95	58
Middle East and Africa	31	5	1,000	177	—	—
Russia and Caspian	25	2	—	—	—	—
Other areas	5	2	100	44	50	13
Total consolidated	737	431	17,927	6,762	36,031	22,754
Equity affiliates						
Canada	8	4	93	47	6	3
Russia and Caspian	28	9	69	25	—	—
Other areas	31	5	—	—	—	—
Total equity affiliates[4]	67	18	162	72	6	3

[1] Includes wells that have been temporarily suspended.
[2] Includes 5,479 gross and 3,450 net multiple completion wells.
[3] Includes 93 gross and 47 net stratigraphic test wells related to the Surmont heavy-oil project.
[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
2007											
Unproved property acquisition	$ 5	202	207	117	—	122	—	—	—	446	2,030
Proved property acquisition	—	42	42	—	—	—	2	—	—	44	1,729
	5	244	249	117	—	122	2	—	—	490	3,759
Exploration	115	468	583	196	235	147	73	37	21	1,292	78
Development	567	2,375	2,942	1,252	1,871	1,275	404	462	73	8,279	2,394
	$687	3,087	3,774	1,565	2,106	1,544	479	499	94	10,061	6,231
Costs incurred of equity affiliates	$ —	—	—	4,117	—	—	314	1,749	51	—	6,231
2006											
Unproved property acquisition	$ 4	860	864	554	113	—	30	—	39	1,600	143
Proved property acquisition	13	15,784	15,797	8,296	1,169	525	856	—	252	26,895	2,647
	17	16,644	16,661	8,850	1,282	525	886	—	291	28,495	2,790
Exploration	131	332	463	182	172	231	57	47	27	1,179	58
Development	629	1,733	2,362	1,926	1,653	919	249	371	141	7,621	1,326
	$777	18,709	19,486	10,958	3,107	1,675	1,192	418	459	37,295	4,174
Costs incurred of equity affiliates	$ —	—	—	—	—	—	183	3,854	137	—	4,174
2005											
Unproved property acquisition	$ 1	14	15	68	—	26	85	83	—	277	796
Proved property acquisition	16	767	783	—	—	6	569	125	—	1,483	1,763
	17	781	798	68	—	32	654	208	—	1,760	2,559
Exploration	64	74	138	163	117	204	67	37	11	737	60
Development	650	688	1,338	782	1,402	682	137	372	42	4,755	449
	$731	1,543	2,274	1,013	1,519	918	858	617	53	7,252	3,068
Costs incurred of equity affiliates	$ —	—	—	—	—	—	54	2,903	111	—	3,068

- Costs incurred include capitalized and expensed items.
- Acquisition costs include the costs of acquiring proved and unproved oil and gas properties. In 2007, equity affiliate acquisition costs were due to the EnCana business venture. In 2006 in our 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
2007											
Proved properties	$10,182	28,645	38,827	17,330	20,615	8,014	2,758	2,135	641	90,320	12,491
Unproved properties	848	1,137	1,985	1,798	446	795	281	131	83	5,519	3,360
	11,030	29,782	40,812	19,128	21,061	8,809	3,039	2,266	724	95,839	15,851
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	14,843
Capitalized costs of equity affiliates	$ —	—	—	4,771	—	—	606	9,466	—	—	14,843
2006											
Proved properties	$ 9,567	26,227	35,794	14,455	17,773	6,870	2,577	1,669	633	79,771	11,550
Unproved properties	840	1,045	1,885	1,425	365	743	321	117	72	4,928	944
	10,407	27,272	37,679	15,880	18,138	7,613	2,898	1,786	705	84,699	12,494
Accumulated depreciation, depletion and amortization	3,573	5,525	9,098	2,795	7,450	1,581	737	3	81	21,745	933
	$ 6,834	21,747	28,581	13,085	10,688	6,032	2,161	1,783	624	62,954	11,561
Capitalized costs of equity affiliates	$ —	—	—	—	—	—	180	8,310	3,071	—	11,561

- Capitalized costs include the cost of equipment and facilities for oil and gas producing activities. These costs include the activities of our E&P and LUKOIL Investment segments, excluding pipeline and marine operations, liquefied natural gas operations, a Canadian Syncrude operation, crude oil and natural gas marketing activities, and downstream operations.
- Proved properties include capitalized costs for oil and gas leaseholds holding proved reserves, development wells and related equipment and facilities (including uncompleted development well costs), and support equipment.
- Unproved properties include capitalized costs for oil and gas leaseholds under exploration (including where petroleum liquids and natural gas were found but determination of the economic viability of the required infrastructure is dependent upon further exploratory work under way or firmly planned) and for uncompleted exploratory well costs, including exploratory wells under evaluation.

■ Standardized Measure of Discounted Future Net Cash Flows Relating to Proved Oil and Gas Reserve Quantities

Amounts are computed using year end prices and costs (adjusted only for existing contractual changes), appropriate statutory tax rates and a prescribed 10 percent discount factor. Continuation of year-end economic conditions also is assumed. The calculation is based on estimates of proved reserves, which are revised over time as new data become available. Probable or possible reserves, which may become proved in the future, are not considered. The calculation also requires assumptions as to the timing of future production of proved reserves, and the timing and amount of future development, including dismantlement, and production costs.

While due care was taken in its preparation, we do not represent that this data is the fair value of our oil and gas properties, or a fair estimate of the present value of cash flows to be obtained from their development and production.

Discounted Future Net Cash Flows

	Millions of Dollars										
	Consolidated Operations										
	Alaska	Lower 48	Total U.S.	Canada	Europe	Asia Pacific	Middle East and Africa	Russia and Caspian	Other Areas	Total	Equity Affiliates
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
2005											
Future cash inflows	$96,574	48,560	145,134	11,907	74,790	31,310	19,337	11,069	787	294,334	111,825
Less:											
Future production and transportation costs*	34,586	10,425	45,011	2,892	12,055	5,343	3,442	2,410	488	71,641	47,634
Future development costs	4,569	1,686	6,255	965	7,517	2,920	474	1,917	149	20,197	4,760
Future income tax provisions	20,421	12,831	33,252	2,349	37,208	9,653	13,882	2,163	80	98,587	17,052
Future net cash flows	36,998	23,618	60,616	5,701	18,010	13,394	1,539	4,579	70	103,909	42,379
10 percent annual discount	19,414	11,934	31,348	2,184	6,006	5,639	560	4,168	56	49,961	25,720
Discounted future net cash flows	$17,584	11,684	29,268	3,517	12,004	7,755	979	411	14	53,948	16,659
Discounted future net cash flows of equity affiliates	$ —	—	—	—	—	—	1,865	5,024	9,770	—	16,659

**Includes taxes other than income taxes.*

Excludes discounted future net cash flows from Canadian Syncrude of $4,484 million in 2007, $2,220 million in 2006 and $2,159 million in 2005.

Sources of Change in Discounted Future Net Cash Flows

	Millions of Dollars					
	Consolidated Operations			Equity Affiliates		
	2007	2006	2005	**2007**	2006	2005
Discounted future net cash flows at the beginning of the year	**$ 51,590**	53,948	35,488	**12,433**	16,659	8,210
Changes during the year						
Revenues less production and transportation costs for the year*	**(24,441)**	(25,133)	(18,867)	**(3,288)**	(3,379)	(2,586)
Net change in prices, and production and transportation costs*	**49,447**	(18,928)	46,332	**10,082**	(5,582)	6,555
Extensions, discoveries and improved recovery, less estimated future costs	**6,985**	3,867	3,942	**2,188**	401	2,201
Development costs for the year	**7,289**	7,020	4,282	**2,346**	1,327	449
Changes in estimated future development costs	**(10,813)**	(6,195)	(3,261)	**(3,468)**	(1,291)	(142)
Purchases of reserves in place, less estimated future costs	**51**	24,203	6,610	**2,989**	1,945	2,361
Sales of reserves in place, less estimated future costs	**(1,347)**	(506)	(306)	**(9,619)**	2	(34)
Revisions of previous quantity estimates**	**(79)**	(7,028)	(175)	**3,855**	107	1,245
Accretion of discount	**8,561**	9,759	5,728	**1,809**	2,215	1,032
Net change in income taxes	**(20,081)**	10,583	(25,825)	**700**	29	(2,632)
Other	**—**	—	—	**—**	—	—
Total changes	**15,572**	(2,358)	18,460	**7,594**	(4,226)	8,449
Discounted future net cash flows at year end	**$ 67,162**	51,590	53,948	**20,027**	12,433	16,659

**Includes taxes other than income taxes.*
***Includes amounts resulting from changes in the timing of production.*

- The net change in prices, and production and transportation costs is the beginning-of-the-year reserve-production forecast multiplied by the net annual change in the per-unit sales price, and production and transportation cost, discounted at 10 percent.
- Purchases and sales of reserves in place, along with extensions, discoveries and improved recovery, are calculated using production forecasts of the applicable reserve quantities for the year multiplied by the end-of-the-year sales prices, less future estimated costs, discounted at 10 percent.
- The accretion of discount is 10 percent of the prior year's discounted future cash inflows, less future production, transportation and development costs.
- The net change in income taxes is the annual change in the discounted future income tax provisions.

5-Year Financial Review (Millions of Dollars Except as Indicated)

	2007	2006	2005	2004	2003
Selected Income Data					
Sales and other operating revenues	$ 187,437	183,650	179,442	135,076	104,246
Total revenues and other income	$ 194,495	188,523	183,364	136,916	105,097
Income from continuing operations	$ 11,891	15,550	13,640	8,107	4,593
Effective income tax rate	48.9%	45.1	42.1	43.6	44.9
Net income	$ 11,891	15,550	13,529	8,129	4,735
Selected Balance Sheet Data					
Current assets	$ 24,735	25,066	19,612	15,021	11,192
Net properties, plants and equipment	$ 89,003	86,201	54,669	50,902	47,428
Goodwill	$ 29,336	31,488	15,323	14,990	15,084
Total assets	$ 177,757	164,781	106,999	92,861	82,455
Current liabilities	$ 26,882	26,431	21,359	15,586	14,011
Long-term debt	$ 20,289	23,091	10,758	14,370	16,340
Total debt	$ 21,687	27,134	12,516	15,002	17,780
Joint venture acquisition obligation — related party	$ 6,294	—	—	—	—
Minority interests	$ 1,173	1,202	1,209	1,105	842
Common stockholders' equity	$ 88,983	82,646	52,731	42,723	34,366
Percent of total debt to capital*	19%	24	19	26	34
Selected Statement of Cash Flows Data					
Net cash provided by operating activities from continuing operations	$ 24,550	21,516	17,633	11,998	9,167
Net cash provided by operating activities	$ 24,550	21,516	17,628	11,959	9,356
Capital expenditures and investments	$ 11,791	15,596	11,620	9,496	6,169
Cash dividends paid on common stock	$ 2,661	2,277	1,639	1,232	1,107
Other Data					
Per average common share outstanding					
Income from continuing operations					
Basic	$ 7.32	9.80	9.79	5.87	3.37
Diluted	$ 7.22	9.66	9.63	5.79	3.35
Net income					
Basic	$ 7.32	9.80	9.71	5.88	3.48
Diluted	$ 7.22	9.66	9.55	5.80	3.45
Cash dividends paid on common stock	$ 1.64	1.44	1.18	.895	.815
Common shares outstanding at year-end (in millions)	1,571.4	1,646.1	1,377.8	1,389.5	1,365.6
Average common shares outstanding (in millions)					
Basic	1,624.0	1,586.0	1,393.4	1,381.6	1,361.0
Diluted	1,645.9	1,609.5	1,417.0	1,401.3	1,370.9
Employees at year end (in thousands)	32.6	38.4	35.6	35.8	39.0

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

5-Year Operating Review

E&P	2007	2006	2005	2004	2003
	Thousands of Barrels Daily (MBD)				
Net Crude Oil Production					
United States	363	367	353	349	379
Europe	210	245	257	271	290
Asia Pacific	87	106	100	94	61
Canada	19	25	23	25	30
Middle East and Africa	81	106	53	58	69
Other areas	10	7	—	—	3
Total consolidated	770	856	786	797	832
Equity affiliates	84	116	121	108	102
	854	972	907	905	934
Net Natural Gas Liquids Production					
United States	98	79	50	49	48
Europe	14	13	13	14	9
Asia Pacific	14	18	16	9	—
Canada	27	25	10	10	10
Middle East and Africa	2	1	2	2	2
	155	136	91	84	69
	Millions of Cubic Feet Daily (MMCFD)				
Net Natural Gas Production*					
United States	2,292	2,173	1,381	1,388	1,479
Europe	961	1,065	1,023	1,119	1,215
Asia Pacific	579	582	350	301	318
Canada	1,106	983	425	433	435
Middle East and Africa	125	142	84	71	63
Other areas	19	16	—	—	—
Total consolidated	5,082	4,961	3,263	3,312	3,510
Equity affiliates	5	9	7	5	12
	5,087	4,970	3,270	3,317	3,522

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

	Thousands of Barrels Daily				
Syncrude Production	23	21	19	21	19
Midstream					
Natural Gas Liquids Extracted*	211	209	195	194	215

**Includes ConocoPhillips' share of equity affiliates.*

R&M	2007	2006	2005	2004	2003
Refinery Operations*					
United States					
Crude oil capacity**	2,035	2,208	2,180	2,164	2,168
Crude oil runs	1,944	2,025	1,996	2,059	2,074
Refinery production	2,146	2,213	2,186	2,245	2,301
International					
Crude oil capacity**	687	651	428	437	442
Crude oil runs	616	591	424	396	414
Refinery production	633	618	439	405	412
Petroleum Products Sales					
United States					
Gasoline	1,244	1,336	1,374	1,356	1,369
Distillates	872	850	876	744	755
Other products	432	531	519	564	492
	2,548	2,717	2,769	2,664	2,616
International	697	759	482	477	430
	3,245	3,476	3,251	3,141	3,046

**Includes ConocoPhillips' share of equity affiliates, except for the company's share of LUKOIL, which is reported in the LUKOIL Investment segment.*
***Weighted-average crude oil capacity for the period.*

LUKOIL Investment*	2007	2006	2005	2004	2003
Crude oil production (MBD)	401	360	235	38	—
Natural gas production (MMCFD)	256	244	67	13	—
Refinery crude processed (MBD)	214	179	122	19	—

**Represents ConocoPhillips' net share of the company's estimate of LUKOIL's production and processing.*

Board of Directors

Richard L. Armitage, 62, 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 service awards and U.S. and foreign decorations. Also a director of ManTech International Corp. Lives in Arlington, Va. (4)

Richard H. Auchinleck, 56, 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)

Norman R. Augustine, 72, director of Lockheed Martin Corporation from 1995 to 2005. Chairman of Lockheed Martin Corporation from 1996 to 1998. CEO of Lockheed Martin from 1996 to 1997. President of Lockheed Martin Corporation from 1995 to 1996. CEO of Martin Marietta from 1987 to 1995. Also a director of The Black & Decker Corporation and The Procter & Gamble Company. Lives in Potomac, Md. (3)

James E. Copeland, Jr., 63, CEO of Deloitte & Touche USA, and its parent company, Deloitte & Touche Tohmatsu, from 1999 to 2003. A director of Coca-Cola Enterprises and Equifax Inc. since 2003 and a director of Time Warner Cable Inc. since 2006. Also senior fellow for corporate governance with the U.S. Chamber of Commerce and a global scholar with the Robinson School of Business at Georgia State University. Lives in Duluth, Ga. (1, 2)

Kenneth M. Duberstein, 63, chairman and CEO of the Duberstein Group, a strategic planning and consulting company, since 1989. Served as White House chief of staff and deputy chief of staff to President Ronald Reagan. Also a director of The Boeing Company, Fannie Mae, The Travelers Companies, Inc. and Mack-Cali Realty Corporation. Lives in Washington, D.C. (5)

Ruth R. Harkin, 63, senior vice president, international affairs and government relations, for 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. Also a member of the Iowa board of regents and a director of AbitibiBowater Inc. Lives in Alexandria, Va. (2, 5)

Charles C. Krulak, 65, executive vice chairman and chief administration officer of MBNA Corporation from 2004 to 2005. Chairman and CEO of MBNA Europe Bank Limited from 2001 to 2004. Senior vice chairman of MBNA America from 1999 to 2001. Commandant and Vice Commander of the Marine Corps and member of the Joint Chiefs of Staff from 1995 to 1999. Holds the Defense Distinguished Service medal, the Silver Star, the Bronze Star with Combat "V" and two gold stars, the Purple Heart with gold star and the Meritorious Service medal. Also a director of Freeport-McMoRan Copper & Gold Inc. and Union Pacific Corporation. Lives in Wilmington, Del. (1)

Harold McGraw III, 59, 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 New York, N.Y. (3)

James J. Mulva, 61, 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. Also a director of M.D. Anderson Cancer Center and member of The Business Council and The Business Roundtable. Serves as a trustee of the Boys and Girls Clubs of America. (2)

Harald J. Norvik, 61, chairman and partner of Econ Management 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. (3)

William K. Reilly, 68, president and CEO of Aqua International Partners, an investment group which 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)

William R. Rhodes, 72, chairman, president and CEO of Citibank, N.A., since 2005. Senior vice chairman of Citigroup Inc. since 2001. Chairman of Citicorp/Citibank from 2003 to 2005. Senior vice chairman of Citicorp/Citibank from 2002 to 2003. Vice chairman of Citigroup Inc. from 1999 to 2001. Vice chairman of Citicorp/Citibank from 1991 to 2001. Also a director of Private Export Funding Corporation and the Council of the Americas. Lives in New York, N.Y. (3)

Officers*

James J. Mulva, Chairman and Chief Executive Officer

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

James L. Gallogly, Executive Vice President, Refining, Marketing and Transportation

John E. Lowe, Executive Vice President, Exploration and Production

Stephen R. Brand, Senior Vice President, Technology

W.C.W. Chiang, Senior Vice President, Commercial

Sigmund L. Cornelius, Senior Vice President, Planning, Strategy and Corporate Affairs

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

Luc J. Messier, Senior Vice President, Project Development

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

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

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

Carin S. Knickel, Vice President, Human Resources

Other Corporate Officers

Rand C. Berney, Vice President and Controller

J.W. Sheets, Vice President and Treasurer

Glenda Schwarz, General Auditor and Chief Ethics Officer

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 Flesher, Vice President, Drilling & Production

Darren Jones, President, Global Gas, Strategic Planning and Business Development

Jim Knudsen, President, U.S. Lower 48

A. Roy Lyons, President, Latin America

Kevin O. Meyers, President, Canada

Don E. Wallette, President, Russia and Caspian Region

Paul Warwick, President, Europe and West Africa

Refining and Marketing

Stephen R. Barham, President, Transportation

Gregory J. Goff, President, Strategy, Integration and Specialty Businesses

Robert J. Hassler, 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

John W. Wright, President, Gas and Power

Glenn E. Simpson, President, Asia Supply and Trading

Todd W. Fredin, President, Europe, Africa and Middle East Trading

As of March 1, 2008.

J. Stapleton Roy, 72, managing director and vice chairman of Kissinger Associates, Inc. Assistant Secretary of State for intelligence and research from 1999 to 2000. Attained the highest rank in the Foreign Service, career ambassador, while serving as ambassador to Singapore, Indonesia and the People's Republic of China. Also a member of the board of Freeport-McMoRan Copper & Gold Inc. Lives in Bethesda, Md. (4)

Bobby S. Shackouls, 57, chairman of Burlington Resources from 1997 to 2006. President and CEO of Burlington Resources from 1995 to 2006. Member of the board of the Domestic Petroleum Council, vice chairman of the Texas Heart Institute, executive board member of the Sam Houston Area Council, and member of the National Board of the Boy Scouts of America. Also a director of The Kroger Co. Lives in Houston, Texas. (5)

Victoria J. Tschinkel, 60, 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, 60, founder, chairperson and CEO of Standard Technology, Inc., a management and technology solutions firm with a focus in the healthcare sector, since 1985. Also a director of Carpenter Technology Corporation and Schering-Plough Corporation. Lives in Bethesda, Md. (4)

William E. Wade, Jr., 65, former president of ARCO (Atlantic Richfield Company). Executive vice president, worldwide exploration and production, ARCO, from 1993 to 1998. Also served as president of ARCO Oil & Gas Company and president of 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

Glossary

Appraisal Drilling: Drilling carried out following the discovery of a new field to determine the physical extent, amount of reserves and likely production rate of the field.

Aromatics: Hydrocarbons that have at least one benzene ring as part of their structure. Aromatics include benzene, toluene and xylenes.

Barrels of Oil Equivalent (BOE): A term used to quantify oil and natural gas amounts using the same measurement. Gas volumes are converted to barrels 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 hydrocarbon materials through thermal cracking. The light materials are suitable as feedstocks to other refinery units for conversion into higher value transportation fuels.

Commercial Field: An oil or natural gas field that, under existing economic and operating conditions, is judged to be capable of generating enough revenues to exceed the costs of development.

Condensate: Light liquid hydrocarbons. As they exist in nature, condensates are produced in natural gas mixtures and separated from the gases by absorption, refrigeration and other extraction processes.

Cost-Advantaged Crude: Lower quality crude oil that is price advantaged in the market due to the limited amount of complex refining capacity available to run it. Typically used to describe crude oils that are dense, high in sulfur content or highly acidic.

Cyclohexane: The cyclic form of hexane used as a raw material to manufacture nylon.

Deepwater: Water depth of at least 1,000 feet.

Directional Drilling: A technique whereby a well deviates from vertical in order to reach a particular part of a reservoir or to safely drill around well bores in highly congested areas.

Distillates: The middle range of petroleum liquids produced during the processing of crude oil. Products include diesel fuel, heating oil and kerosene.

Downstream: Refining, marketing and transportation operations.

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 vessel's hull. This crude oil is then offloaded onto shuttle tankers to be delivered to nearby land-based oil refineries, or offloaded into large crude oil tankers for export to world markets. The gas is exported by pipeline or reinjected back into the reservoir.

Fluid Catalytic Cracking Unit (FCC): A refinery unit that cracks large hydrocarbon molecules into lighter, more valuable products such as gasoline components, propanes, butanes and pentanes, using a powdered catalyst that is maintained in a fluid state by use of hydrocarbon vapor, inert gas or steam.

Gas-to-Liquids (GTL): A process that converts natural gas to clean liquid fuels.

Hydrocarbons: Organic chemical compounds of hydrogen and carbon atoms that form the basis of all petroleum products.

Improved Recovery: Technology for increasing or prolonging the productivity of oil and gas fields. This is a special field of activity and research in the oil and gas industry.

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 in some instances, the difference between sales prices and feedstock and manufacturing costs.

Midstream: Natural gas gathering, processing and marketing operations.

Natural Gas Liquids (NGL): A mixed stream of ethane, propane, butanes and pentanes that is split into individual components. These components are used as feedstocks for refineries and chemical plants.

Olefins: Basic chemicals made from oil or natural gas liquids feedstocks; commonly used to manufacture plastics and gasoline. Examples are ethylene and propylene.

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 manufacturing products including fibers, films and automotive parts.

Reservoir: A porous, permeable sedimentary rock formation containing oil and/or natural gas, enclosed or surrounded by layers of 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 various plastics by polymerization or copolymerization.

Syncrude: Synthetic crude oil derived by upgrading bitumen extractions from mine deposits of oil sands.

Tallow: Animal byproduct fat recovered during food processing; can be used as feedstock to produce biodiesel.

Throughput: The average amount of raw material that is processed in a given period by a facility, such as a natural gas processing plant, an oil refinery or a petrochemical plant.

Total Recordable Rate: A metric for evaluating safety performance calculated by multiplying the total number of recordable cases by 200,000 then dividing by the total number of work hours.

Upstream: Oil and natural gas exploration and production, as well as gas gathering activities.

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.

Stockholder Information

Annual Meeting

ConocoPhillips' annual meeting of stockholders will be at the following time and place:

Wednesday, May 14, 2008, at 10:30 a.m.
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:

Mellon Investor Services, LLC
P.O. Box 3336
South Hackensack, NJ 07606
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.melloninvestor.com/ISD* and following the enrollment instructions.

Information Requests

For information about dividends and certificates, or to request a change of address, stockholders may contact:

Mellon Investor Services, LLC
P.O. Box 3315
South Hackensack, NJ 07606
Toll-free number: (800) 356-0066
Outside the U.S.: (201) 680-6578
TDD: (800) 231-5469
Outside the U.S.: (201) 680-6610
Fax: (201) 329-8967
www.melloninvestor.com

Personnel in the following office 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

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 2007, 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 2008 annual certification to the NYSE no later than 30 days after the date of ConocoPhillips' annual stockholder meeting.

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, environmental and safety 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

Form 10-K and Annual Report

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 — 2007 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 — 2007 Annual Report
B-41 Adams Building
411 South Keeler Ave.
Bartlesville, OK 74004

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600 N. Dairy Ashford
Houston, TX 77079

1013 Centre Road
Wilmington, DE 19805-1297

Stock Transfer Agent and Registrar

Mellon Investor Services, LLC
480 Washington Blvd.
Jersey City, NJ 07310
www.melloninvestor.com

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
600 N. Dairy Ashford, MA2142
Houston, TX 77079

ConocoPhillips

www.conocophillips.com

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