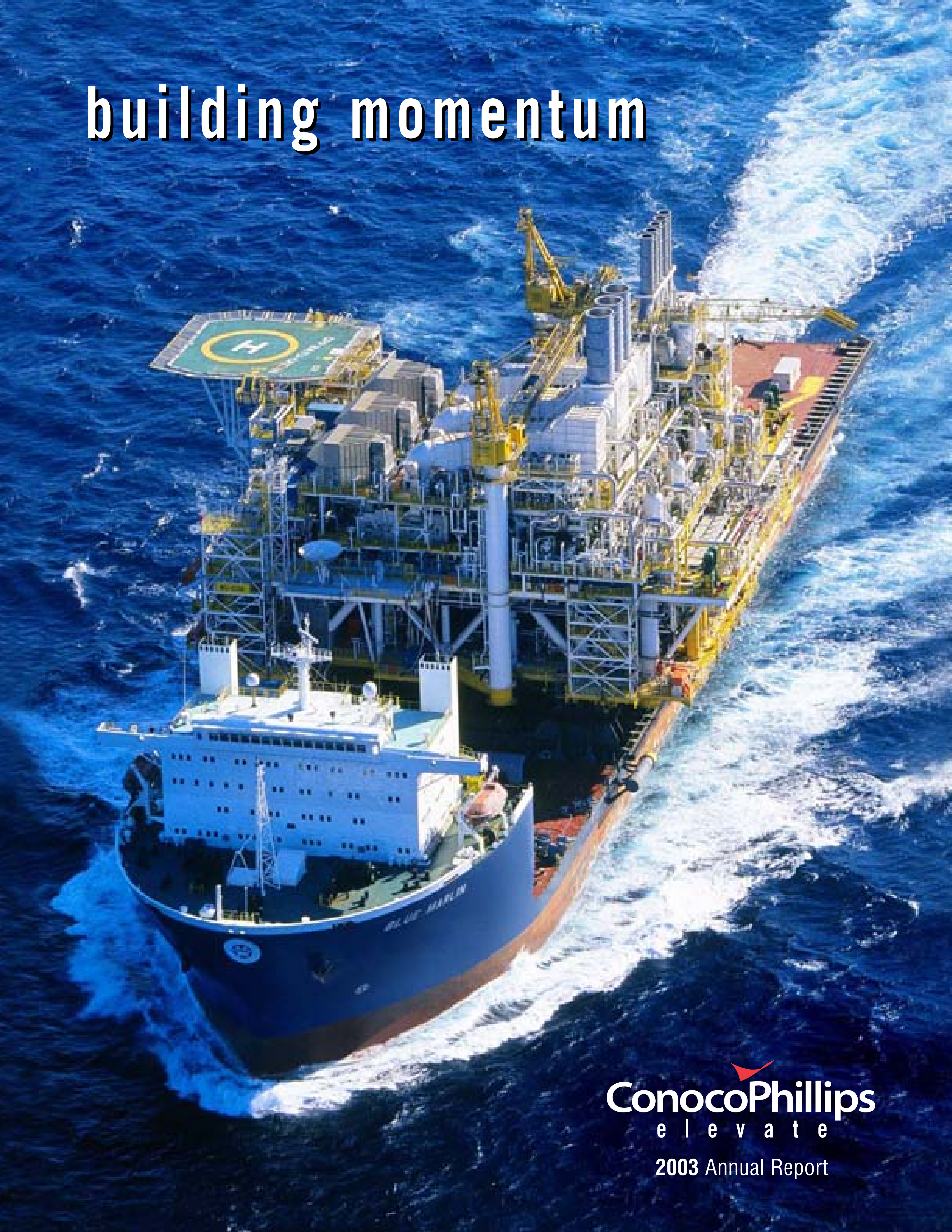
building momentum



ConocoPhillips
elevate

2003 Annual Report

Our Purpose

Use Our Pioneering Spirit to Responsibly Deliver Energy to the World

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, oil and gas proved reserves and production; and the largest refiner in the United States. Worldwide, of nongovernment-controlled companies, ConocoPhillips has the eighth-largest total of proved reserves and is the fourth largest refiner.

ConocoPhillips is known worldwide for its technological expertise in exploration and production, reservoir management and exploitation, liquefied natural gas, 3-D seismic technology, high-grade petroleum coke upgrading, and sulfur removal.

Headquartered in Houston, Texas, ConocoPhillips operates in more than 40 countries. The company has approximately 39,000 employees worldwide and assets of $82.5 billion. ConocoPhillips stock is listed on the New York Stock Exchange under the symbol "COP."

Our Businesses

The company has four core activities worldwide:

- Petroleum exploration and production.
- Petroleum refining, marketing, supply and transportation.
- Natural gas gathering, processing and marketing, including a 30.3 percent interest in Duke Energy Field Services, 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 — gas-to-liquids, power generation, the development and marketing of environmentally friendly fuels technologies, and other emerging technologies — that provide current and potential future growth opportunities.

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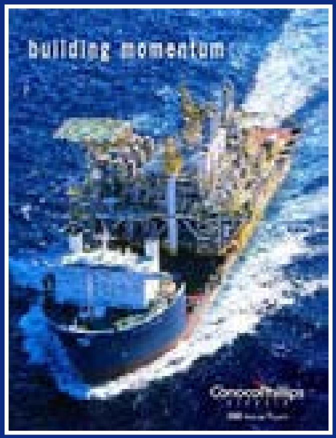
Our Theme: Building Momentum



A ship steaming through the open ocean carries on its deck one of the platforms for the Bayu-Undan project in the Timor Sea. The movement through the water of the ship and its cargo represents the momentum ConocoPhillips is building as it enters its second full year as a combined company. The company achieved excellent financial results in 2003 and enhanced value to its shareholders. ConocoPhillips is continuing to build momentum using a disciplined financial approach to capture synergies and improve the balance sheet, as well as moving forward with the development of legacy upstream projects like Bayu-Undan, which began production of natural gas liquids and condensate in February 2004.

Highlights

	Millions of Dollars Except as Indicated		
	2003	2002	% Change
Financial			
Total revenues	**$105,097**	57,201	84
Income from continuing operations	**$ 4,593**	698	558
Net income (loss)	**$ 4,735**	(295)	—
Per share of common stock — diluted			
Income from continuing operations	**$ 6.70**	1.44	365
Net income (loss)	**$ 6.91**	(.61)	—
Net cash provided by operating activities from continuing operations	**$ 9,167**	4,776	92
Net cash provided by operating activities	**$ 9,356**	4,978	88
Capital expenditures and investments	**$ 6,169**	4,388	41
Total assets	**$ 82,455**	76,836	7
Total debt	**$ 17,780**	19,766	(10)
Mandatorily redeemable preferred securities of a trust subsidiary	**$ —**	350	—
Other minority interests	**$ 842**	651	29
Common stockholders' equity	**$ 34,366**	29,517	16
Percent of total debt to capital*	**34%**	39	(13)
Common stockholders' equity per share (book value)	**$ 50.33**	43.56	16
Cash dividends per common share	**$ 1.63**	1.48	10
Closing stock price per common share	**$ 65.57**	48.39	36
Common shares outstanding at year-end (in thousands)	**682,784**	677,570	1
Average common shares outstanding (in thousands)			
Basic	**680,490**	482,082	41
Diluted	**685,433**	485,505	41
Employees at year-end (in thousands)	**39.0**	57.3	(32)

**Capital includes total debt, mandatorily redeemable preferred securities of a trust subsidiary, other minority interests and common stockholders' equity.*

	2003	2002	% Change
Operating*			
U.S. crude oil production (MBD)	**379**	371	2
Worldwide crude oil production (MBD)	**934**	682	37
U.S. natural gas production (MMCFD)	**1,479**	1,103	34
Worldwide natural gas production (MMCFD)	**3,522**	2,047	72
Worldwide natural gas liquids production (MBD)	**69**	46	50
Worldwide Syncrude production (MBD)	**19**	8	138
Worldwide production on a barrel-of-oil-equivalent basis, including Syncrude (MBD)	**1,609**	1,077	49
Natural gas liquids extracted — Midstream (MBD)	**219**	156	40
Refinery crude oil throughput (MBD)	**2,459**	1,813	36
Refinery utilization rate (%)	**94**	90	4
U.S. automotive gasoline sales (MBD)	**1,369**	1,230	11
U.S. distillates sales (MBD)	**575**	502	15
Worldwide petroleum products sales (MBD)	**3,046**	2,451	24

**Includes ConocoPhillips' share of equity affiliates where applicable.*

The ConocoPhillips merger was consummated on August 30, 2002, and used purchase accounting to recognize the fair value of Conoco Inc. assets and liabilities. Consequently, results for the year 2002 include eight months of activity for Phillips Petroleum Company and four months of activity for ConocoPhillips. Periods prior to the merger reflect only Phillips' results.

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 60 should be read in conjunction with such statements.

"ConocoPhillips," "the company," "we," "us" and "our" are used interchangeably in this report to refer to the businesses of ConocoPhillips and its consolidated subsidiaries. All numerical references to crude oil, natural gas or natural gas liquids production volumes refer to production from proved reserves.

ConocoPhillips' Worldwide Operations

Exploration and Production (E&P)

Profile: Explores for and produces crude oil, natural gas and natural gas liquids on a worldwide basis. Also mines oil sands to upgrade to Syncrude. A key strategy is the development of legacy assets — very large oil and gas developments that can provide strong financial returns over long periods of time — through exploration, exploitation, redevelopments and acquisitions.

Operations: At year-end 2003, ConocoPhillips held a combined 52.6 million net developed and undeveloped acres in 25 countries and produced hydrocarbons in 13. Crude oil production in 2003 averaged 934,000 barrels per day (BPD), gas production averaged 3.5 billion cubic feet per day, and natural gas liquids production averaged 69,000 BPD. Key regional focus areas include Australia; the North Slope of Alaska; Southeast Asia; Canada; the Caspian Sea; offshore China; the Middle East; Nigeria; the North Sea; the Timor Sea; the Lower 48 United States, including the Gulf of Mexico; and Venezuela.

Refining and Marketing (R&M)

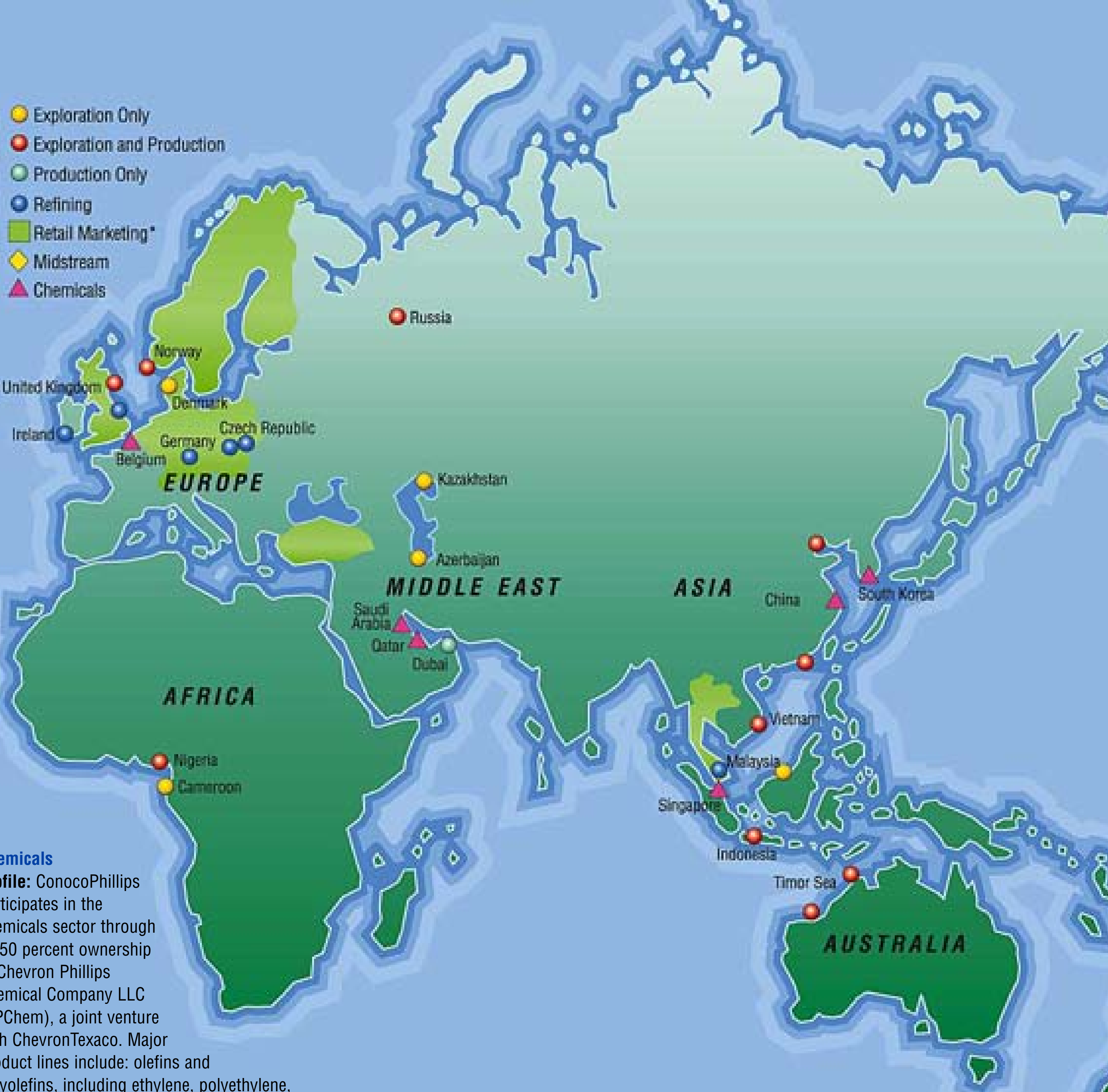
Profile: Refines crude oil and markets and transports petroleum products. ConocoPhillips is the largest refiner in the United States and, of nongovernment-controlled companies, is the fourth-largest refiner in the world.

Operations: *Refining* — At year-end 2003, ConocoPhillips owned 12 U.S. refineries, owned or had an interest in five European refineries, and had an interest in one refinery in Malaysia, totaling a combined net crude oil refining capacity of 2.6 million barrels of oil per day. *Marketing* — At year-end 2003, ConocoPhillips' gasoline and distillates were sold through approximately 17,300 branded outlets in the United States, Europe and Southeast Asia. In the United States, products were primarily marketed under the Phillips 66, 76 and Conoco brands. In Europe and Southeast Asia, the company marketed primarily under the JET and ProJET brands. ConocoPhillips also marketed lubricants, commercial fuels, aviation fuels and liquid petroleum gas. ConocoPhillips' refined products sales were 3 million BPD in 2003. The company also participated in joint ventures that support the specialty products business. *Transportation* — R&M owned, or had an interest in, about 32,800 miles of pipeline systems in the United States at year-end 2003.

Midstream

Profile: Midstream consists of ConocoPhillips' 30.3 percent interest in Duke Energy Field Services, LLC (DEFS), as well as certain ConocoPhillips assets in the United States, Canada and Trinidad. Midstream gathers natural gas, extracts and sells the natural gas liquids (NGL), and sells the remaining (residue) gas.

Operations: At year-end 2003, DEFS' gathering and transmission systems included some 58,000 miles of pipelines, mainly in six of the major U.S. gas regions, plus western Canada. DEFS also owned and operated, or had an equity interest in, 66 NGL extraction plants. Raw natural gas throughput averaged 6.7 billion cubic feet per day, and NGL extraction averaged 365,000 BPD in 2003. In addition to its interest in DEFS, ConocoPhillips owned or had an interest in an additional 11 gas processing plants and six NGL fractionators at year-end 2003.



Chemicals

Profile: ConocoPhillips participates in the chemicals sector through its 50 percent ownership of Chevron Phillips Chemical Company LLC (CPChem), a joint venture with ChevronTexaco. Major product lines include: olefins and polyolefins, including ethylene, polyethylene, normal alpha olefins and plastic pipe; aromatics and styrenics, including styrene, polystyrene, benzene, cyclohexane, paraxylene and K-Resin® styrene-butadiene copolymer; and specialty chemicals and plastics.

Operations: CPChem's major facilities in the United States are at Baytown, Borger, Conroe, La Porte, Orange, Pasadena, Port Arthur and Old Ocean, Texas; St. James, La.; Pascagoula, Miss.; and Marietta, Ohio. The company also has nine plastic pipe plants and one pipe fittings plant in eight states, and a petrochemical complex in Puerto Rico. Major international facilities are in Belgium, China, Saudi Arabia, Singapore, South Korea and Qatar. CPChem also has a plastic pipe plant in Mexico.

*Retail Marketing is located in the following countries:

Austria	Norway
Belgium	Poland
Czech Republic	Slovakia
Denmark	Switzerland
Finland	Sweden
Germany	Thailand
Hungary	Turkey
Luxembourg	United Kingdom
Malaysia	United States

Building Momentum and Shareholder Value

To Our Shareholders:
In our first full year, ConocoPhillips began 2003 by elevating expectations — and ended the year by exceeding them. We realized greater synergies from the merger than we initially predicted and have generated more proceeds than expected from the assets we have sold. In 2003, we achieved net income of $4.7 billion, or $6.91 per share. We reduced our debt by $4.8 billion, improving our debt-to-capital ratio, and we improved our adjusted return on capital employed (ROCE) to 15.8 percent*. Total shareholder return for 2003 was 39.5 percent.

Our 2003 results show that we have a strong workforce of skilled and talented employees who are successfully implementing our disciplined strategy to build ConocoPhillips into a stronger, more competitive company. Our challenge for the future is to continue building momentum.

Three Disciplines: Costs, Capital Spending and Financial

Our success in 2003 was due in part to strictly adhering to discipline in three areas: costs, capital spending and financial.

Discipline in our cost structure includes the continuing capture of synergies that resulted from the merger and adhering to operating excellence in our businesses. Our initial synergy capture target was $750 million. By the end of the year, we had captured nearly $1.31 billion in pretax synergies, plus $150 million in capital synergies*.

These synergies have been realized by eliminating duplicate organizations, utilizing best practices, and by leveraging greater economies of scale. Restructuring and asset dispositions resulted in a 33 percent reduction in worldwide employee headcount by the end of 2003.

Archie W. Dunham, *Chairman, and* ***J.J. Mulva,*** *President and Chief Executive Officer*

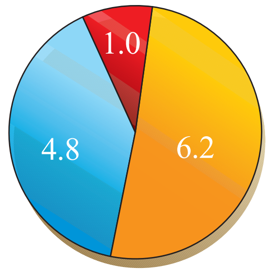
**See page 7 for reconciliation to comparable data determined in accordance with generally accepted accounting principles (GAAP).*

Discipline in capital spending means investing in only the best projects that meet financial and strategic objectives and maintaining the size of the capital budget even though we had improved cash flows as a result of higher commodity prices and margins. We have more opportunities for investment than our capital budget allows. The basis for prioritizing capital investments remains the development of legacy projects that have the capacity to generate strong income and attractive returns over a long period of time.

Of the $6.9 billion we have budgeted for capital spending in 2004, about 75 percent will go to Exploration and Production (E&P) operations and roughly 20 percent to Refining and Marketing (R&M). This is in keeping with our efforts to increase the proportion of upstream assets in the portfolio. Over time, we plan to organically grow E&P to at least 65 percent of the total capital employed from its current level of approximately 60 percent.

Financial discipline means improving our financial flexibility. We made significant progress in this respect in 2003. We used excess cash from operations and proceeds from asset divestitures to reduce debt. The divestiture program has focused on selling nonstrategic upstream assets and rationalizing the downstream retail marketing portfolio, including the sale of The Circle K Corporation completed late last year. The company received $2.7 billion from asset sales in 2003, and we expect to realize another estimated $1 billion from asset sales in 2004. Continuing with our financial discipline will strengthen our balance sheet and give us greater financial flexibility.

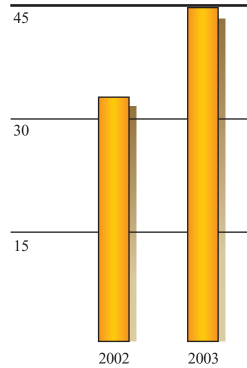
Uses of Cash (Billions of Dollars)



Total sources of cash for the year equaled approximately $12 billion. Proceeds from asset sales and strong commodity prices provided the company an opportunity to fund its capital program, accelerate debt reduction and pay a competitive dividend.

Total sources of cash = $12.0 billion
(Cash flow from operations plus proceeds from asset sales)

Market Capitalization (Billions of Dollars)



ConocoPhillips' market capitalization was almost $45 billion at the end of 2003, representing a 37 percent increase over 2002. The company had 682.8 million shares outstanding at Dec. 31, 2003, with a year-end closing price of $65.57. The sharp increase in market capitalization in 2003 reflects the significant rise in the company's stock price during the year.

Exploration and Production

As evidenced by our capital spending allocations, our intention is to grow the company's E&P operations where we see the greatest opportunities to invest in higher-return projects. We plan to do this by building a broad, diversified portfolio of large legacy assets around the world. We intend to increase reserves and production and do it profitably. This means maximizing returns both from mature assets, and from new, longer-term projects that will be our legacy positions of the future.

Our existing production areas will be the foundation of future growth. The legacy businesses in North America and the North Sea will focus on improving production efficiency, reducing costs, managing decline rates and investing selectively in highly profitable opportunities.

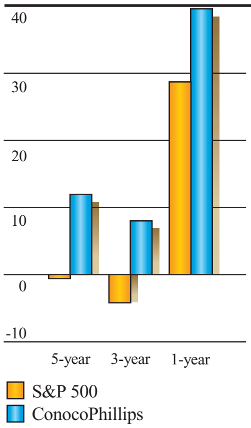
Legacy businesses account for roughly 80 percent of our production and nearly 70 percent of our reserves. Over time, we plan to shift some of the capital in these base legacy businesses to building new legacy positions in energy growth areas — specifically, Asia Pacific, the Caspian region, Nigeria, Venezuela and the Middle East.

The company is focusing its exploration efforts in areas with existing large, high-value reserves like deepwater Nigeria. We're also looking in areas with sizable reserves such as the Caspian Sea, where there is significant potential for long-term returns. Further, the company will seek access to undeveloped, already discovered reserves in areas with high potential, such as Russia and the Middle East, where a large proportion of the world's remaining proven reserves are located. This strategy has led to opportunities such as signing a Heads of Agreement for the Qatargas 3 liquefied natural gas (LNG) project in the State of Qatar.

Natural gas, because it is environmentally friendly, is firmly established as the preferred fuel for power generation in developed nations and is rapidly gaining favor in the developing world. In the future, natural gas could overtake oil in terms of its contribution to world energy. Much of this demand will be met in the form of LNG.

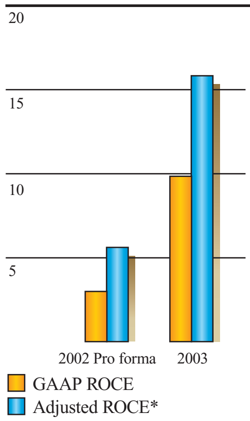
LNG is a growing part of our business portfolio. ConocoPhillips has its own proprietary LNG technology and nearly 35 years of experience through the operation of a plant in Kenai, Alaska, that supplies LNG to utility customers in Japan. In 2003, the company announced its intention to become involved in major LNG projects in Qatar, Nigeria, and Venezuela. ConocoPhillips already has a large project under way in the Timor Sea to supply LNG to Japan beginning in 2006. The company also is developing plans to build several LNG receiving and

Total Shareholder Return (Annual Average Return in Percent)



ConocoPhillips' total shareholder return for 2003 was 39.5 percent, ranking the company number one among its peers. Over the past three years, ConocoPhillips' return to shareholders was 7.7 percent, while over the last five-year period it was 12.0 percent.

Return on Capital Employed (ROCE) (Percent)



ConocoPhillips' return on average capital employed for 2003 was 9.8 percent and 15.8 percent, if adjusted for purchase accounting. The adjusted return represents a 182 percent increase over 2002, reflecting the company's strong 2003 earnings and debt reduction.

regasification terminals in North America to help meet the growing demand for natural gas in the United States.

Refining and Marketing

ConocoPhillips is the largest refiner in the United States and is uniquely positioned to take advantage of a strong U.S. market outlook. In late 2002, we outlined plans to improve the ROCE for R&M, and since then, R&M has demonstrated strong adjusted midcycle ROCE performance. In 2003, this segment committed to a 4 percentage-point improvement over two years. It captured a large portion of that goal during the year by exercising capital discipline, capturing synergies and improving refinery utilization.

In 2004, R&M's challenge will be to maintain the strong ROCE improvement realized during 2003. To meet this challenge and further improve, R&M must continue streamlining processes in order to lower costs, while maintaining and improving reliability, and leveraging organizational knowledge and diversity. R&M also must complete its asset divestiture program and minimize future capital investment, especially with the significant U.S. clean fuels investment. Finally, R&M must be successful in achieving its increased synergy capture target of $750 million.

Given increasingly strict product specifications and clean fuels requirements worldwide, ConocoPhillips' leadership in coking, alkylation, hydroprocessing and sulfur removal technologies provides R&M with a competitive edge. For example, ConocoPhillips' S Zorb™ Sulfur Removal Technology provides a cost-competitive means for reducing sulfur content in gasoline well below 10 parts per million, meeting government standards anywhere in the world.

R&M historically is both capital intensive and highly competitive. Yet our strategically positioned, low-cost and highly efficient operations will help provide attractive returns, even under the most difficult market conditions.

Emerging Businesses

ConocoPhillips is exercising the same capital and cost discipline in emerging businesses that we are elsewhere in the company. We have several technologies with both long-term and short-term potential. Our immediate goal is to apply technologies to our existing businesses, but we also want to ensure the company is positioned for the future.

One example is our gas-to-liquids (GTL) technology, which converts natural gas into transportable liquids, creating an opportunity to develop some of the world's remote, large natural gas fields. Our new GTL semi-works facility in Ponca City, Okla., completed in 2003, is meeting the technical and commercial milestones set for the project. In December, we signed a Statement of Intent with Qatar Petroleum to build a full-scale GTL plant in Ras Laffan, Qatar.

Financial Strategies

ConocoPhillips is an integrated company, providing diversified cash flow and earnings, which in turn, provide opportunities for greater profitability and less income volatility over time. Because a strong balance sheet is a strategic asset, we plan to continue to improve the debt-to-capital ratio from its current level of 34 percent to about 30 percent.

We believe that regular, incremental increases in dividends support our objective of creating value for our shareholders. In 2003, the board of directors approved a 7.5 percent increase in the quarterly dividend rate for the company's common stock. The increase reflects the company's strong financial performance in 2003 and our confidence in the future performance of our company.

Ethics and Values

In 2003, we published ConocoPhillips' commitment to sustainable development. In this statement, we reaffirm the commitment of our predecessors to the values of transparency, accountability, ethics and safety, as well as concern for the environment, our employees and the communities where we operate. It is our belief that the company will enhance both its short-term and long-term profitability by understanding and responding to the opportunities and risks associated with the changing needs

**See page 7 for reconciliation to comparable data determined in accordance with generally accepted accounting principles (GAAP).*

and expectations of society. In other words, we believe that being an even more responsible company will make us better able to generate value for our shareholders.

A healthy company is the product of a healthy spirit, and our people have it: Our SPIRIT of Performance — Safety, People, Integrity, Responsibility, Innovation and Teamwork. SPIRIT is the foundation of our culture, and these values help guide every business decision we make. Our people and their commitment to the SPIRIT values are what set ConocoPhillips apart. It is because of the dedication of thousands of talented employees that we have been able to accomplish so much in a short period of time.

The Year Ahead

We have had a good first full year. We're very pleased with our operating performance and the benefit we received from strong market conditions. We are excited about the prospects that lie ahead for ConocoPhillips.

What do we have in front of us? More synergies to capture, continued discipline on costs and capital, developing a portfolio of growth projects, and continuous improvement in our financial position.

ConocoPhillips will work to improve shareholder returns through reliable operations, reducing operating costs and optimizing performance throughout our large, integrated system. We succeeded this past year in making ConocoPhillips a stronger company, both financially and in terms of our asset portfolio. We have dedicated ourselves to ensuring we have the right people, technologies and assets to build momentum for the long term.

Archie W. Dunham
Chairman

J.J. Mulva
President and
Chief Executive Officer

March 1, 2004

Reconciliations to generally accepted accounting principles

Return on Capital Employed Adjusted for Purchase Accounting

Millions of Dollars Except as Indicated

	2003		2002	
	GAAP ROCE	Adjusted for Purchase Accounting	GAAP ROCE	Pro Forma Adjusted for Purchase Accounting
Income from continuing operations	$ 4,593	4,593	698	918
After-tax interest and minority interest	562	562	399	625
Alaska DD&A on asset step-up	—	124	—	125
Adjusted ROCE Income	$ 5,155	5,279	1,097	1,668
Average capital employed	$52,649	52,649	36,983	44,119
Purchase adjustments:				
Acquisition of ARCO Alaska	—	(2,159)	—	(2,429)
Acquisition of Tosco	—	(2,959)	—	(3,353)
ConocoPhillips merger	—	(14,052)	—	(8,448)
Adjusted Average Capital Employed	$52,649	33,479	36,983	29,889
Return on Capital Employed	9.8%	15.8	3.0	5.6

2003 Income Summary Run Rate Reconciliation (Millions of Dollars)

First-Half 2002 Income Baseline	
Conoco as reported	$234
Phillips as reported	249
Price adjustments	315
Other*	114
Discontinued operations	(58)
First-Half 2002 Baseline	$854

Primarily consists of adjustments such as tax adjustments, merger costs, impairments, income from certain hedge transactions, gains/losses on assets sales and foreign currency transactions.

Income Baseline to Actuals	
Annualized baseline	$1,708
Price adjustments	2,677
Disposition impact	46
R&M energy costs	(151)
Merger costs	(223)
Other*	(118)
Adjusted Baseline	$3,939
Reported 2003 Income From Continuing Operations	$4,593
Business Improvement	$ 654

Primarily includes adjustments such as foreign currency transactions, pending claims and settlements, impairments, impacts of a Venezuela shutdown, and tax adjustments.

Synergy Capture Run Rate	
Business improvement	
Earnings impact	$ 654
Pretax run rate at 50 percent	1,308
Capital synergies*	150

Captured in internal tracking systems; primarily resulted from reduced exploration spending, negotiation of better procurement terms and the application of best practices.

An Interview with President and CEO Jim Mulva

Q ***What actions will you take to maintain the level of performance you had in 2003?***

We need to continue our disciplined approach that was instrumental to our success in 2003. We ran our operations well in 2003. This, along with the discipline in our capital program, synergy capture and successful implementation of our asset disposition program, allowed us to reduce debt, thereby improving our balance sheet.

We must continue to run our operations well in 2004. We have more synergies to capture, and we must complete our asset divestiture program. We are investing in a portfolio of large growth projects that we must deliver on time and within budget. We will remain disciplined in our approach to costs, capital spending and finance. And there will be accountability for every decision we make and goal that we set.

We also must capture new opportunities around the world, but that doesn't mean we need to make significant acquisitions. We already have the scope, scale and diversity of assets to compete with the largest companies in our industry. Our primary approach is to deliver shareholder value through organic growth.

We are committed to sustainable development, with a particular emphasis on safety and environmental stewardship.

And, finally, we want to promote and develop a culture of elevated expectations of performance from our employees. It will take a motivated and dedicated work force to achieve the elevated expectations we have set for ourselves. We want ConocoPhillips to be more than just a good company — we have much higher expectations. We want to be a company that employees want to work for and companies and governments want to partner with.

Q ***How has the merger gone?***

The merger has gone exceedingly well. We were well prepared and capitalized on opportunities to continue to grow the company. We have achieved more synergies than we originally anticipated, and we're continuously discovering new ways to leverage the combination of assets, technology and sharing of knowledge enabled by the merger.

But the merger is behind us. We spent 2003, our first full year as a company, putting in place the organization to run the company. We operated well and captured synergies, but we also increased reserves and did not miss opportunities. We are a new company with a new culture. Now we are looking forward to growing our Exploration and Production (E&P) business, improving the returns from our Refining and Marketing (R&M) assets, maintaining financial discipline and generating superior returns for our shareholders.

Q ***How can shareholders be assured that the company's reserves are reported accurately?***

ConocoPhillips' proved reserves are reviewed annually to ensure that all reserve determinations are made in accordance with a disciplined internal policy. This policy requires the financial commitment to proceed with development of such reserves and any appropriate government and partner approvals before reserves are booked. ConocoPhillips' proved reserves are routinely evaluated and determined independently of our co-venturers.

Q ***What is ConocoPhillips' natural gas strategy?***

Worldwide demand for natural gas is growing steadily, and ConocoPhillips is positioned to be a significant supplier. We have large natural gas reserves around the world, and we have technologies such as gas-to-liquids (GTL) and liquefied natural gas (LNG) that we are leveraging to meet demand. Our technical and commercial knowledge, combined with our financial strength, makes us one of the few players with the ability to capture opportunities in resource-rich regions around the world.

We are pursuing development opportunities for significant Arctic natural gas resources in the Mackenzie Delta in Canada and the North Slope of Alaska. We are moving forward with the formal regulatory process for the Mackenzie Delta pipeline. We expect this pipeline to come online as early as 2009. We are still seeking additional legislative support for the Alaska North Slope pipeline project, and we are hopeful that this project will start up sometime in the first half of the next decade.

ConocoPhillips has a wealth of experience with LNG. We've been a long-time exporter of LNG from our plant in Kenai, Alaska, to Japan, and we are planning very substantial growth in our LNG business. In 2003, the Bayu-Undan LNG project was approved, and we signed heads of

J.J. Mulva, *President and Chief Executive Officer* agreements for both Qatargas 3 and the Nigerian Brass LNG project. We're moving ahead with the necessary studies to develop LNG from Venezuela, and we have plans to develop several LNG receiving terminals in the United States.

We've made excellent progress in proving our GTL technology through our demonstration plant in Ponca City, Okla. Late last year, we signed a Statement of Intent (SOI) to develop a reservoir-to-market GTL project in Qatar. We expect the SOI will lead to a more definitive agreement in 2004.

Q ***How are ConocoPhillips' E&P and R&M business segments integrated, and what is the benefit of this integration?***

Being an integrated energy company provides a balance of opportunities for more stable profitability in varying market conditions. This exists financially through participation in multiple facets of the value chain and, in some cases, more directly by linking certain of our operations. Our refining and midstream businesses provide ready markets for our crude oil and natural gas production. The marketing of our crude oil and natural gas, and buying the same commodities for our refineries, is supported and managed by our Commercial organization. Commercial optimizes the value chain and improves the profitability of the company's E&P, R&M and Midstream assets. Our marketing business provides an outlet for our refined products. Chevron Phillips Chemical Company also is a purchaser of natural gas liquids and refined products.

One example of how we benefit from integration is in our significant heavy-oil positions in Venezuela and Canada that are leveraged with our U.S. refining system. Heavy oil from Venezuela is upgraded and shipped to our refineries on the U.S. Gulf Coast, which are equipped with cokers and are able to process these low-cost, high-sulfur, heavy crude oils. We currently process some Canadian crude oil at our Billings, Mont., refinery, and we are preparing our Wood River refinery in Illinois to be able to process heavy oil from the Surmont field in Canada that is expected to begin production in 2006. So each of our businesses is supporting the next business in the supply chain.

Q ***What is ConocoPhillips' strategy in the Middle East? Russia?***

ConocoPhillips maintains an aggressive, yet prudent, growth strategy for the Middle East, Russia and Caspian region. An example of our successful execution of this growth strategy is the two agreements that we signed for large gas projects with Qatar Petroleum in 2003.

As we continue to progress our growth strategy for these pre-eminent oil and gas resource areas, our focus is on securing large, legacy-scale investment opportunities that meet our investment criteria. ConocoPhillips has the financial resources, technology, business processes, commercial expertise and experience to secure, and then successfully complete a project of any scale. We can compete with anyone.

ConocoPhillips has a long and rich history of successfully doing business in the Middle East, Russia and Caspian region, and over the decades we have built strong and mutually beneficial relationships within the industry and with governments. We are committed to a long-term presence in the region and look forward to the continued successful implementation of our strategy.

Q ***What is ConocoPhillips doing to demonstrate its commitment to sustainable development?***

The world needs more energy, more economic growth and more opportunity for development. Yet the world demands that these needs should not be filled at the expense of environmental and social systems we depend on for survival. In 2003, we published our position on sustainable development that includes nine commitments, the first of which is to provide ever-cleaner energy. We already are making great strides in this commitment: we're spending approximately $1.5 billion over the next few years to complete our clean fuels program within our worldwide refining system. We even have our own clean fuels technology, S Zorb™ Sulfur Removal Technology, that we license to other refiners.

We also are well positioned to be a leading provider of another cleaner source of energy: natural gas. We have natural gas reserves around the world and plan to grow this part of our company over the next several years. We have technologies such as LNG and GTL, which enable the commercialization of reserves in some areas that were once considered uneconomical to develop.

ConocoPhillips is a leader in the industry in the use of double-hulled tankers that offer greater environmental protection than single-hulled tankers. By 2008, our entire fleet will consist of double-hulled tankers.

When conducting exploration and production activities, we go to great lengths to minimize our impact to the environment — such as utilizing ice roads and ice pads during winter drilling activities in tundra regions, or using drilling techniques that require smaller surface footprints than previous methods.

We make efforts to positively impact the communities where we operate. Though we directly create employment opportunities in these communities, we also want to ensure they are not completely dependent on the energy industry. For example, in Venezuela, our Ameriven joint venture sponsors a program that provides vocational training in carpentry and electrician skills to young people in the communities near our operations. The training helps prepare the students to earn incomes independent of the oil industry.

These are just a few examples of how we already live by our commitment to sustainable development, but this is just the beginning. Later in 2004, we plan to issue a complete sustainable development report that advances our commitment to transparency and accountability by further outlining our sustainability strategies and describing our progress on key sustainable development issues.

operating review

The Ekofisk growth project is one of the many ways in which ConocoPhillips is building momentum in its operations. Other new Exploration and Production projects were announced in 2003 for Qatar, Canada, Nigeria and Alaska. On the downstream side, Refining and Marketing (R&M) excelled in driving down costs and progressed its clean fuels program. R&M also successfully divested a large number of retail marketing assets as part of a strategy to focus on the wholesale marketing business.

The Ekofisk field in the Norwegian North Sea is one of ConocoPhillips' most prolific legacy assets. The field produced its 2 billionth barrel of oil in November, after 32 years of production. Plans to expand production from the field were approved in 2003.

Competing Globally And Achieving Results

Exploration and Production (E&P) operated well in 2003, allowing the company to fully benefit from higher crude oil and natural gas prices. In addition, E&P successfully met key project milestones and secured several new opportunities.

"E&P delivered strong results," says Bill Berry, executive vice president of E&P. "In addition to solid financial earnings, we exceeded our production goal, met our disposition target and captured several new opportunities through exploration and business development. This high level of performance would not have been possible without the hard work of our employees around the globe, and our results are an indication of their strong commitment to operating excellence. Our robust performance also reflects the strength of our legacy assets, and we will continue to focus on large oil and gas projects with positive, long-term financial returns in order to grow E&P."

ConocoPhillips produced approximately 1.59 million barrels of oil equivalent per day (BOEPD) in 2003, excluding Syncrude production of 19,000 barrels per day. The company replaced 106 percent of its 2003 production, and excluding sales and acquisitions, replaced 133 percent of production. Total proved reserves were 7.8 billion barrels of oil equivalent at year-end 2003, excluding 265 million barrels of Syncrude.

A large percentage of the company's current proved production and reserves is derived from the legacy assets located in Alaska, U.S. Lower 48, North Sea, Canada, Venezuela and Indonesia. New legacy projects also are being developed in these areas, as well as the Asia Pacific region, the Caspian Sea, the Middle East and West Africa.

W.B. Berry, *Executive Vice President, Exploration and Production*

The company's exploration and business development program is expected to drive future production and reserve growth. "We are exploring in areas with potentially large, high-value reserves, as well as areas where the scale of the prospect offers the opportunity to achieve low operating, finding and development costs," explains Berry. "We also are placing a greater emphasis on the appraisal and development of undeveloped reserves in basins with high potential. This includes large, integrated liquefied natural gas (LNG) projects like Qatargas 3 that was announced in 2003."

As the company maintains its existing legacy assets and develops new opportunities, it is committed to optimizing its operations. "We will focus on improving production efficiency, controlling costs, capturing additional synergies, minimizing the impact of decline in some of our mature legacy assets and investing in highly profitable opportunities," says Berry. "Our objective is to drive continuous improvement in our operations and financial returns, in both the long term and short term."

The Americas

Canada: Surmont Project Moving Forward

After securing the necessary regulatory approvals in 2003, the Surmont oil sands project located in Alberta, Canada, is moving forward. Construction of the facilities will begin in early 2004. Surmont is expected to begin production in 2006 and achieve peak net production of 47,000 barrels per day of bitumen, or heavy oil, in subsequent years as the project is fully developed.

The company also owns an interest in a second oil sands operation — Syncrude Canada Ltd. — a joint-venture company that mines shallow deposits of oil sands, extracting the bitumen and upgrading it into a light crude

The heavy-oil upgrader for the Hamaca project in Venezuela is scheduled to start up in 2004. The facility will upgrade heavy crude oil into lighter crude oil that will be further processed into fuels and other products at U.S. refineries.

A worker puts the finishing touches on the hull of the Magnolia tension-leg platform in South Korea before being loaded for shipment to Texas. The Magnolia platform will be located in the Gulf of Mexico in nearly 4,700 feet of water — a record depth for this type of floating structure.

An expansion of the water and gas handling facilities at the Alpine field on Alaska's North Slope will enable increased oil production from the field and help maintain reservoir pressure. Phase I of the project is expected to start up in 2004, and with the completion of Phase II in 2005, net production from the field is expected to increase by 26,000 BOEPD.

called Syncrude. An expansion project is under way with production expected to be onstream in 2005.

In addition to heavy oil, the company is pursuing a major gas project in Canada. In 2003, ConocoPhillips and its co-venturers filed a preliminary information package to assist regulators in a formal review of a proposed 761-mile pipeline that could come online as early as 2009, bringing gas from the Mackenzie Delta region of the Canadian Arctic to Alberta. Within the Mackenzie Delta region, the company operates the onshore Parsons Lake field and holds substantial offshore resources.

Alaska: Alpine Expansion Project Under Way

As Alaska's largest producer of oil and gas, ConocoPhillips has operations in three key areas of the North Slope — Western North Slope, Prudhoe Bay and Kuparuk — as well as in the Cook Inlet.

On the Western North Slope, a major expansion project is under way to increase oil production capacity from the Alpine field. Phase I of the project is expected to start up in 2004, and with the completion of Phase II in 2005, net production from the field is expected to increase by 26,000 BOEPD. Production from Alpine began in 2000, and the field reached a production milestone — its 100 millionth barrel — in late 2003. The Alpine field maintained an average net production of 64,500 BOEPD in 2003.

The Greater Prudhoe Area (GPA) consists of the Prudhoe Bay field, its satellites and the Greater Point McIntyre Area fields. The Prudhoe Bay satellites continued their strong performance in 2003 with net production of 16,200 BOEPD, and further development is planned in 2004. Average net production from GPA was 180,100 BOEPD in 2003.

The Greater Kuparuk Area (GKA) includes the Kuparuk field and four satellites. GKA reached a major milestone in early 2004, producing its 2 billionth barrel of crude oil. Development of the Palm discovery expanded the Kuparuk field and helped maintain GKA's net production of 104,400 BOEPD in 2003.

In addition to its existing operations on the North Slope, the company is pursuing development opportunities for the significant Arctic natural gas resource in the Prudhoe Bay and Point Thomson areas. Federal and state fiscal and regulatory legislation is being pursued in order to facilitate a pipeline project that would deliver the gas to North American markets.

In 2003, ConocoPhillips renewed its right-of-way agreements for 30 years each on the Kuparuk, Alpine and Oliktok pipelines and the Trans Alaska Pipeline System (TAPS). The company also increased its ownership in TAPS from 26.8 percent to 28.3 percent.

ConocoPhillips' natural gas operations in the Cook Inlet delivered average net production of 175 million cubic feet per day in 2003. Most of the gas is converted into LNG by the company's facility in Kenai and shipped to Japanese utilities. The remainder is sold in the local market. The Kenai facility utilizes the company's proprietary LNG technology and has operated for nearly 35 years.

U.S. Lower 48: Deepwater Project to Come Onstream in 2004

Magnolia, the company's deepwater project in the Gulf of Mexico (GOM), is expected to begin production in 2004. Magnolia is located in nearly 4,700 feet of water — making it the world's deepest tension-leg platform. Net production is expected to peak in 2005 at approximately 49,000 BOEPD.

In the GOM Green Canyon area, the company made a deepwater discovery with the Lorien well in 2003. Evaluation of the discovery is ongoing. Elsewhere in Green Canyon, the K2 accumulation is being evaluated for project sanctioning.

In the GOM Mississippi Canyon area, the company has an interest in Ursa — one of the largest fields in the Gulf. Ursa and the adjacent Princess development produced at an average net rate of 19,300 BOEPD in 2003.

Onshore, ConocoPhillips' operations are primarily concentrated in four areas: South Texas, San Juan Basin, Permian Basin and the Texas/Oklahoma Panhandle. In these areas, the company's principal focus is on efficiently developing and producing natural gas and liquids. Total onshore net production averaged 263,200 BOEPD in 2003.

Aiding its delivery of natural gas to the growing North American markets, ConocoPhillips is participating in

Appraisal of the giant Kashagan field in the Caspian Sea continued in 2003 while co-venturers progressed development plans for the project. Two additional significant discoveries were made in 2003 near the field.

several LNG receiving terminals in key ports, including Quintana, Texas. Pending regulatory and other approvals, the Quintana facility could begin commercial operations as early as 2007.

Venezuela: Building on a Solid Foundation

ConocoPhillips has a strong position in the heavy-oil business in Venezuela, with a significant ownership position in two of the four producing heavy-oil projects in the Orinoco Oil Belt — Petrozuata and Hamaca.

Petrozuata — a joint venture with Petroleos de Venezuela S.A. (PDVSA) — produced an average of 51,600 net barrels of oil per day (BOPD) in 2003. Hamaca, a joint venture with PDVSA and ChevronTexaco, produced an average of 22,100 net BOPD in 2003. Hamaca's net production is expected to increase to 71,000 BOPD after an upgrader facility is completed in 2004.

Offshore, the company is operator of the Corocoro field in the Gulf of Paria West Block, a recent conventional oil discovery. The Phase I development plan for Corocoro received government approval in 2003.

Complementing its position in Corocoro and the Gulf of Paria West Block, the company acquired a 37.5 percent interest in the adjacent Gulf of Paria East Block in 2003. Exploration drilling is under way.

Building on the strength of its heavy- and conventional-oil projects, the company expanded its natural gas position by acquiring a 40 percent interest in Block 2 of Plataforma Deltana. Plataforma Deltana is a major natural gas region on Venezuela's continental shelf that is near the Corocoro field. Appraisal work will begin in 2004. Natural gas from Plataforma Deltana will likely be processed into LNG for export to the United States.

Europe and Africa

North Sea: Ekofisk Growth Project and Britannia Satellite Development Add Value

A growth project that will increase recovery of oil and gas from the Greater Ekofisk Area operations in the Norwegian North Sea is under development. The growth project includes the construction of a new steel wellhead and processing platform, and an overall capacity increase as a result of modifications at several existing facilities and the drilling of 25 new wells. First production from the new platform is expected in 2005. In 2003, the Greater Ekofisk Area reached a significant milestone — producing its 2 billionth barrel of crude oil. Average net production from the Greater Ekofisk Area was 147,700 BOEPD in 2003.

Elsewhere in the Norwegian North Sea, the Grane field began production ahead of schedule in 2003. Net production from Grane was 4,900 BOEPD at year-end 2003. Peak production of 14,000 BOEPD is expected in 2005.

The Britannia field, one of the largest gas and gas condensate fields on the U.K. continental shelf, marked five years of production in 2003. Britannia's net production averaged 79,600 BOEPD in 2003. ConocoPhillips and its co-venturers sanctioned development of the Britannia satellite fields Brodgar and Callanish in 2003. Pending government approval, first production from the two satellites could be as early as 2007.

The Clair field is under development offshore the Shetland Islands in the Atlantic Margin. The platform and associated facilities will be installed in 2004, with first production anticipated in late 2004 and net peak production of 14,000 BOEPD anticipated in 2005.

Nigeria: LNG Facility Being Studied

ConocoPhillips and its co-venturers signed a Heads of Agreement to progress the development of an LNG facility in Nigeria's central Niger Delta. The agreement covers the front-end engineering and design studies for the facility, which could include two trains, each nominally sized at 5 million metric tons per year. The engineering studies are expected to be completed in 2005, and the facility could start up in 2009.

The LNG facility will allow ConocoPhillips to monetize uncommitted and underutilized gas from its onshore leases, and could expand to handle gas from future exploration in deep water offshore and other sources. The company acquired two highly prospective deepwater blocks in 2003 in the western Niger Delta, bringing ConocoPhillips' total number of blocks in the area to four. Exploration drilling is scheduled to begin in 2004.

Net crude oil production from the Peng Lai 19-3 field in China's Bohai Bay averaged 14,800 barrels per day in 2003 after initial production began in late 2002. China is one of several key growth areas in the Asia Pacific region, where the company also has E&P projects under way in Australia, Indonesia, the Timor Sea and Vietnam.

Asia Pacific

China: Bohai Bay Production Increases

ConocoPhillips is building on its success in Bohai Bay. Phase I production from the Peng Lai 19-3 field continued to ramp up and produced 14,800 net BOPD in 2003. Preliminary engineering for Phase II production is under way. Peng Lai 19-3 began production in 2002.

In the South China Sea, the company set a new record for extended reach drilling of a horizontal well. Completed in March 2003, the A23 well was drilled to a satellite oil field as part of the development program for the Xijiang 24-3 field. The Xijiang development consists of three fields, and in 2003, had an average net production of 10,900 BOPD.

Indonesia: Belanak Development Taking Shape

As the largest foreign leaseholder in Indonesia, ConocoPhillips' assets are concentrated in two key areas: the West Natuna Sea and South Sumatra. A third area, offshore East Java, is the focus of exploration and appraisal activity.

The Belanak oil and gas field is the largest development in the West Natuna Sea. The development will utilize one of the largest and most complex floating production, storage and offloading vessels ever built. Production is expected to begin in 2005. The natural gas from the Belanak field is being combined with existing developments in the area and sold under long-term contract to Singapore and Malaysia.

In South Sumatra, ConocoPhillips is developing the Corridor Block and the large Suban gas field. The company successfully drilled the Suban-8 exploration well and progressed Phase II development plans in 2003. Gas produced in South Sumatra is currently sold domestically to Caltex and exported to Singapore. A Heads of Agreement signed in 2003 provides for future gas sales to West Java.

Net production in Indonesia averaged 58,500 BOEPD in 2003.

Vietnam: Su Tu Den Production Begins, Discovery Made Nearby

Production from the Su Tu Den field — located in the Cuu Long Basin offshore Vietnam — began ahead of schedule in 2003. At year-end, average net production from Su Tu Den was 15,700 BOPD. Additional development and appraisal wells are planned in 2004 for the Su Tu Den field and the adjacent Su Tu Vang field.

In late 2003, ConocoPhillips and its co-venturers made a discovery in the nearby Su Tu Trang field. Technical evaluation of Su Tu Trang's reservoir potential is ongoing.

Elsewhere in the Cuu Long Basin, the company has an interest in the Rang Dong field. Field facilities were upgraded in 2003 to enable gas lift, gas export and water injection. Net average production at year-end was 14,300 BOEPD.

His Excellency Abdullah Bin Hamad Al Attiyah, Second Deputy Prime Minister and Minister of Energy and Industry of Qatar, Chairman and Managing Director of Qatar Petroleum; and President and CEO Jim Mulva signed agreements for two major natural gas development projects in Qatar, including the development of the Qatargas 3 liquefied natural gas project and a gas-to-liquids plant.

Timor Sea: First Liquids Production from Bayu-Undan
Production from Phase I of Bayu-Undan, a major natural gas and gas liquids development in the Timor Sea, began in February 2004. Phase I consists of a gas-recycle facility producing and processing wet gas; separating, storing and marketing condensate, propane and butane; and reinjecting dry gas back into the reservoir. Full gross daily design rates of 1.1 billion cubic feet (BCF) of gas; 115,000 barrels of combined condensate, propane and butane; and 950 million cubic feet of dry gas recycled into the reservoir are anticipated in 2004.

Phase II of the Bayu-Undan project was approved in 2003. This phase includes a 3.52 million-ton-per-year LNG facility near Darwin, Australia, as well as a gas pipeline from Bayu-Undan to Darwin and the LNG facility. LNG shipments to customers in Japan are expected to begin in 2006, when construction of the facility is complete.

Middle East, Russia and Caspian Region

Russia: Satellite Fields Come Onstream Under Budget, Ahead of Schedule
Two new satellite fields — East Kolva and Dyusushev — began production in 2003, several months ahead of schedule and at a lower cost than budgeted. Production from the fields is tied to the Ardalin field processing facility. In 2003, Ardalin and its satellites averaged net production of 13,600 BOEPD. Located in the Timan-Pechora basin in northern Russia, the fields are operated by the Polar Lights Company, a joint venture in which ConocoPhillips owns 50 percent.

Caspian Sea: Two Discoveries Made Near Giant Kashagan Field
Two discoveries — Aktote-1 and Kashagan Southwest-1 — were made in the North Caspian Sea in late 2003 near the giant Kashagan field that was declared a commercial discovery in 2002. An appraisal plan is being prepared for each of these discoveries. Additionally, work on the Kairan exploration well progressed in 2003.

In 2003, ConocoPhillips was one of five co-venturers in the Republic of Kazakhstan's North Caspian Sea Production Sharing Agreement (PSA) to exercise its pre-emptive rights in the sale of BG International's interest in the PSA. Upon completion of the pre-emption transactions, the company's interest will increase from 8.33 percent to 10.19 percent.

Qatar: Agreements Signed for LNG Facility, GTL Plant
ConocoPhillips has signed a Heads of Agreement (HOA) with Qatar Petroleum for the development of Qatargas 3 — a large-scale LNG project — and a Statement of Intent for the construction of a gas-to-liquids (GTL) plant.

The Qatargas 3 project includes facilities to produce gas from Qatar's North field, yielding about 7.5 million tons of LNG per year, in a new, world-class LNG train to be constructed at Ras Laffan Industrial City. The LNG would be shipped from Qatar to the United States in a fleet of state-of-the-art LNG carriers. ConocoPhillips would purchase the LNG and be responsible for marketing it within the United States. Average gross daily sales volumes are expected to be approximately 1 BCF per day, with startup anticipated in 2009. The HOA provides the framework for the necessary project agreements and the completion of key feasibility studies.

The GTL plant would use the technology proven at ConocoPhillips' GTL demonstration plant in Ponca City, Okla. Engineering and design studies are under way. The GTL chemical conversion turns natural gas into clean fuels that can be economically delivered to markets around the world.

E&P Results	2003	2002
Net income (MM)	**$4,302**	1,749
Worldwide crude oil production (MBD)	**934**	682
Worldwide natural gas production (MMCFD)	**3,522**	2,047
Finding and development costs ($/BOE)*	**$ 4.29**	4.31

**Five-year average.*

E&P earnings improved primarily due to additional volumes as a result of the merger and higher realized worldwide crude oil and natural gas prices.

Performance Exceeds Expectations

ConocoPhillips' global Refining and Marketing (R&M) business made strong progress in 2003, especially with regard to improvements in return on capital employed (ROCE), synergy capture and the divestment of non-strategic assets.

R&M committed to improving its adjusted midcycle ROCE four percentage points in two years. The organization captured a significant portion of the expected improvement in 2003. Contributing to the improvement was the successful capture of synergies and an increase in the company's worldwide crude oil refinery utilization rate from 90 percent to 94 percent.

According to Jim Nokes, executive vice president of ConocoPhillips' global downstream business, the one clear challenge before his organization is to maintain the strong ROCE improvement realized during 2003 and to further improve in 2004. "We can achieve this goal by continuing to capture synergies and operating our assets effectively and efficiently," says Nokes.

In addition, Nokes says there will be a focus on simplifying and streamlining the business to take advantage of the organization's size and position, while completing approximately $900 million of asset dispositions in the coming year.

Nokes believes that employees can have the biggest impact in generating earnings through operating excellence — flawless execution, strong reliability and uptime, and sharing best practices to enhance the business.

***Jim W. Nokes,** Executive Vice President, Refining, Marketing, Supply and Transportation*

"We are confident in the capability and competency of our employees around the globe," says Nokes. "No matter how good the market or our assets, we could not have achieved the success that we did in 2003 without the work of talented and dedicated people."

Another of R&M's strengths is its integration with the Exploration and Production (E&P) business segment. R&M operations also are tightly coordinated across the refining, marketing and transportation functions.

"By developing integrated global and regional strategies, and coordinating efforts across our Commercial organization and operating groups, we believe the company can produce superior results across the value chain," says Nokes.

Refining Finds Ways to Lower Costs

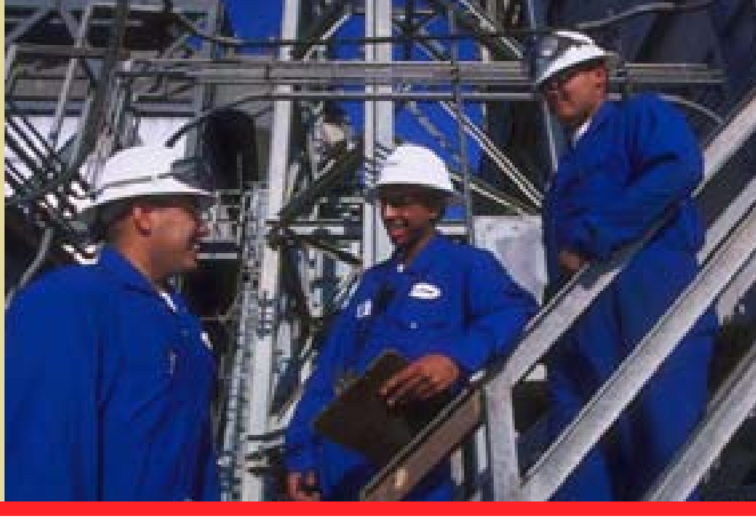
The global refining network has a crude oil processing capacity of 2.6 million barrels per day (BPD), including 2.2 million BPD in the United States. ConocoPhillips owns or has an interest in 12 U.S. refineries, five European refineries and one refinery in Southeast Asia.

"The company's strong refining position is integrated with and helps support the company's E&P business segment by providing a market for some of ConocoPhillips' crude oil production," says Bob Hassler, president of East/Gulf Coast refining.

In 2003, ConocoPhillips acquired a crude unit, coker and other refining assets from Premcor's Hartford, Ill., refinery, located adjacent to ConocoPhillips' Wood River refinery. The acquired refining units are being tied into the Wood River facility and will enable the refinery to process low-cost, heavy crude oils. This capability will help lower crude acquisition costs at the refinery, and it is expected that Wood River will process heavy crude from ConocoPhillips' Canadian oil sands project when production comes online. The integration of the Hartford units is expected to be completed in the second quarter of 2004.

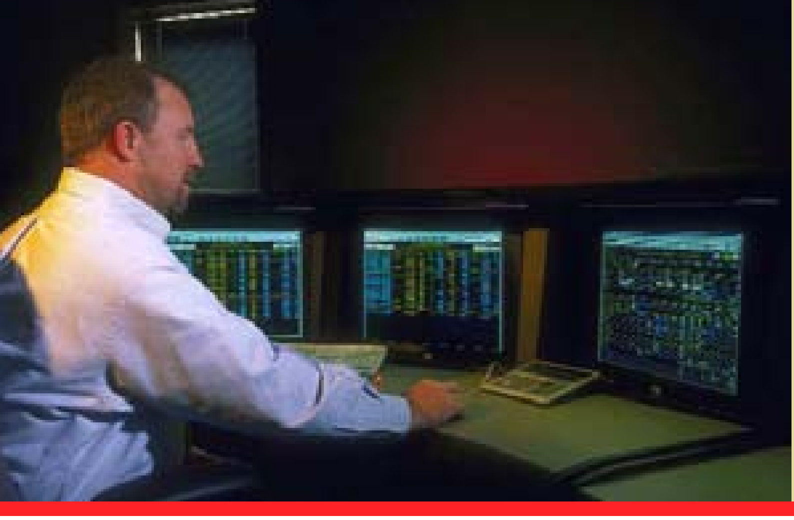
(Left to right) Eduardo Izarraraz, Robert Williams and Fidel Lopez are employees at ConocoPhillips' Los Angeles, Calif., refinery. The Los Angeles refinery is a key link in the company's West Coast refining system, supplying refined products to markets in California, Nevada and Arizona.

The company's Wood River, Ill., refinery will process low-cost, heavy crude oils thanks to a strategic acquisition of neighboring refining assets. The move will decrease crude oil acquisition costs and position the refinery to process crude oil from the company's Surmont heavy-oil project in Canada, scheduled to begin production in 2006.



The Ferndale, Wash., refinery made major improvements that are expected to help increase its average net income by more than 80 percent. The installation of a state-of-the-art fluid catalytic cracker (FCC) and a 50 percent expansion of the alkylation unit not only significantly improved the reliability of the facility but also increased the average clean product yield by more than 6 percent. Another benefit of these projects is the production of excess alkylate, a valuable blending component needed to make California-grade gasoline. Ferndale ships excess alkylate to ConocoPhillips' other West Coast refineries, reducing the company's cost of buying alkylate on the market.

In Europe, the Humber refinery in the United Kingdom supports ConocoPhillips' major worldwide position in graphite coke and provides a significant cost advantage by processing low-cost residual oil and turning it into premium coke, gasoline and diesel fuel. The highly complex ConocoPhillips European refineries provide the company a higher yield of light-oil products. In addition,



The operation and monitoring of the company's vast U.S. pipeline network were consolidated into a single, modernized control center in Ponca City, Okla., in 2003. Operators like Billy Cunningham use computers and satellite technology to control the flow of products in the company's pipelines from hundreds of miles away.

ConocoPhillips' three U.S. marketing brands are getting a new look, as demonstrated by recently updated locations in Seattle, Wash., Denver, Colo., and Santa Fe, N.M. The reimaging campaign gives all three brands a common look and helps identify them with ConocoPhillips.

three of the five European refineries can leverage their inland locations to take advantage of product upgrades versus the spot market, enhancing the net cash margin from those refineries.

The company is continuing to make investments to support clean fuels initiatives within its U.S. refining system. The company's proprietary technologies in alkylation, hydro-processing and sulfur removal play a key role in helping ConocoPhillips operate in a stricter clean fuels environment.

An important milestone in the clean fuels initiative was the completion of the 20,000 BPD S Zorb™ Sulfur Removal Technology (S Zorb) unit at the Ferndale refinery. The Ferndale unit is the largest commercialized unit built to date utilizing ConocoPhillips' proprietary S Zorb technology, and the project was brought online within a year from the start of construction. Construction is expected to begin in 2004 on another S Zorb unit at the company's Lake Charles, La., refinery.

ConocoPhillips is positioned to introduce ultra-low sulfur diesel (ULSD) into the marketplace to meet the U.S. regulatory requirement effective in 2006. By investing capital over the next three years, the company is developing the necessary facilities to produce a cleaner-burning diesel fuel, as well as providing other modernizing and process improvements. The new ULSD will minimize tailpipe emissions when combined with improved emission control systems for diesel trucks and buses.

The Rodeo facility, part of the San Francisco, Calif., refinery, is scheduled to complete its ULSD project in early 2005. A new hydrotreater is expected to allow the refinery to manufacture 100 percent of its diesel production as ultra-low sulfur California-highway diesel. The new hydrotreater also should help lower crude oil acquisition costs and improve the utilization of the refinery.

"An additional objective of the project is to give the Rodeo facility the flexibility and capacity to efficiently process Alaska North Slope crude, as well as other crude oils from different sources," says Larry Ziemba, president of Central/West Coast refining.

The company is well positioned to meet European requirements for super-clean fuels that allow no more than 10 parts per million of sulfur in both gasoline and diesel fuel. A new hydrotreater under construction at the Whitegate refinery in southern Ireland will help reduce sulfur content in distillates when it comes online in the first quarter of 2005.

Marketing Strengthens Its Brands

In 2003, the company made significant changes to its marketing business that resulted in simplifying the business, reducing costs, strengthening the brands and customer base, and improving ROCE.

One way marketing contributed to R&M's overall financial success in 2003 was through the sale of certain U.S. marketing assets. During 2003, R&M sold almost $1.5 billion in assets and plans to complete the program during 2004 with the sale of another approximately $900 million of other asset packages, currently in various stages of completion. These transactions should serve to strengthen the company's longer-term ROCE and provide additional funds to reduce debt, strengthening the company's balance sheet.

Most notably, the company exited the New England region and divested the largest segment of its retail business, The Circle K Corporation and its subsidiaries. In addition, the company has signed agreements to sell certain mid-Atlantic marketing assets. The sales are expected to close in 2004.

Once the planned dispositions are complete, Marketing's focus will be on operating its wholesale business, but it will retain and operate approximately 300 to 350 retail outlets that complement the company's refining and transportation network. These outlets are located primarily in the Central, Rockies and West Coast regions of the United States and will utilize the company's family of trusted brands: Conoco, Phillips 66 and 76.

By negotiating long-term supply agreements with the purchasers of the marketing assets sold, the company will continue to supply 1.2 billion gallons per year of gasoline for the next two to five years and, at the same time, reduce the cost of moving those barrels into the marketplace.

"We will focus on the wholesale channel of trade by providing quality fuels at the lowest possible delivery cost

to the marketplace," says Mark Harper, president of U.S. Marketing. "This creates a sustainable, low-cost and ratable demand for our fully integrated refining network."

To improve its ability to compete in the long term, ConocoPhillips has restructured the management and operation of its wholesale marketing business. More than 50 percent of the historical programs provided to marketers and dealers were eliminated and replaced with an allowance that provides greater flexibility to compete with lower-cost competitors. This new approach encourages ConocoPhillips' business partners to strengthen their businesses, while enhancing the overall customer base for both marketers and ConocoPhillips. Improving the viability of the sites that remain within the ConocoPhillips network builds larger, stronger customers, and reduces the cost to serve the entire value chain.

A reimaging campaign was launched in 2003 with the goal of giving all three U.S. marketing brands a consistent look, helping consumers identify with ConocoPhillips while maintaining regional loyalty to the individual brands. Dissemination of the new image into the marketplace is expected to continue over the next three years.

ConocoPhillips took another positive step toward enhancing the value of its U.S. brands by signing a global agreement with Ethyl Corporation to supply detergent additives for all gasoline products at the company's U.S. marketing outlets. Gasoline sold at 76, Conoco and Phillips 66 branded outlets will have the same high-content level of a proprietary detergent additive, greatly exceeding the current industry standard.

Says Harper, "We are distinguishing our brands as the brands of choice among consumers and marketers by providing a quality product that consumers can trust in their vehicles."

ConocoPhillips is a niche player in the European marketplace, where it uses the JET brand in 13 countries. Over the past several years, the company has driven down costs throughout the European network while increasing volume.

"Growth in volume stems from two actions," says Greg Goff, president, Europe and Asia Pacific. "Selling more product through our existing network, and strategically adding sites in selected markets as opportunities become available."

Transportation Maintains Safe, Reliable Networks

By providing a sound and safe infrastructure for the company, Transportation reduces costs and provides supply alternatives in response to changing market conditions.

In 2003, the company consolidated the control and monitoring of its U.S. pipeline networks in a new control center located in Ponca City, Okla. The move, which was completed with no downtime or loss of communications, allows controllers to remotely operate thousands of miles of ConocoPhillips' wholly owned crude oil and product pipelines from one central location.

Additionally, ConocoPhillips has sold 14 product terminals in five states, primarily located along the Colonial Pipeline system, in an effort to reduce costs and eliminate redundancy. The company continues to own and control the inventory and throughput at these terminals under a long-term contract.

ConocoPhillips' marine division set an industry standard by adding four American Bureau of Shipping classed towboats to its inland towing fleet. The towboats *Spirit*, *Integrity*, *Innovator* and *Liberty* are used specifically along the Gulf Coast and allow ConocoPhillips to further capitalize on the synergies of its refineries in the region.

Says Steve Barham, president of Transportation, "We are committed to providing ConocoPhillips with dependable and uncompromised service, whether moving raw or intermediate products between our refineries or delivering refined products to our customers."

R&M Results	**2003**	2002
Net income (MM)	**$1,272**	143
Worldwide crude oil throughput (MBD)	**2,459**	1,813
U.S. petroleum products sales (MBD)	**2,616**	2,289
International petroleum products sales (MBD)	**430**	162

R&M earnings increased primarily as a result of significantly higher U.S. refining margins and additional volumes following the merger.

Midstream

Strategic Changes Under Way For Midstream

ConocoPhillips is reshaping its Midstream segment to focus on its 30.3 percent interest in Duke Energy Field Services, LLC (DEFS), one of the largest natural gas and gas liquids gathering, processing and marketing companies in the United States. During 2003, certain Midstream assets owned outside of DEFS were under consideration for sale to other companies.

Midstream gathers natural gas, processes it to extract natural gas liquids (NGL), and markets the remaining residue gas to electrical utilities, industrial users and gas marketing companies.

Total net NGL extraction in 2003 totaled 219,000 barrels per day (BPD), of which 111,000 BPD came from ConocoPhillips' interest in DEFS and 108,000 BPD from other Midstream assets. ConocoPhillips' share of DEFS raw gas throughput was 2 billion cubic feet per day (BCFD).

Net income from the Midstream segment was $130 million in 2003, a significant increase over 2002 results, primarily because of higher NGL prices and volumes. This improvement was partially offset by higher natural gas prices, which weakened the margin between the price of purchased gas and the selling price of NGL.

"DEFS experienced strong performance in 2003," explains Bill Easter, chairman, president and chief executive officer of DEFS. "In addition to benefiting from higher NGL prices, DEFS made progress in improving its cost structure and further rationalizing its asset base."

As part of its asset rationalization effort, DEFS sold two groups of gas gathering assets outside its core areas of operation; one located in eastern Oklahoma and the other in Mississippi, Texas, Alabama and Louisiana. A third sale of certain West Texas assets is pending. In total, the sales represent less than 5 percent of DEFS' total asset base.

Improved cash flow from operations, asset sales and reduced capital spending allowed DEFS to significantly reduce debt and retire preferred stock during 2003, helping the company maintain an investment-grade credit rating.

DEFS owns the general partner of TEPPCO Partners, L.P., a master limited partnership that has experienced rapid growth in recent years. DEFS benefits from TEPPCO distributions, which rose significantly in 2003, and also

While ConocoPhillips is considering the sale of certain Midstream assets held outside of its interest in DEFS, the company plans to retain other assets that strategically support the company's E&P business, including the San Juan gas plant in New Mexico that processes ConocoPhillips' regional natural gas production.

operates and commercially manages TEPPCO's midstream assets in Wyoming, New Mexico, Colorado and Texas.

A major expansion was completed in late 2003 at TEPPCO's Jonah gas gathering system in southwestern Wyoming, raising system capacity from 880 million cubic feet per day (MMCFD) to 1.2 BCFD. The Jonah system has been expanded three times in the last four years in response to rising gas production in the Green River Basin.

At year-end, sales were under consideration for certain ConocoPhillips Midstream asset packages located mostly in Texas, Louisiana and New Mexico. This reflects the company's interest in divesting properties that do not support its natural gas production or downstream activities and to focus on DEFS as the most effective vehicle for generating income from the processing of third-party gas.

Midstream assets that are not under consideration for sale include the company's strategic interest in a processing plant and a fractionator in the San Juan Basin of New Mexico, which handles large volumes of the company's natural gas production, and Midcontinent NGL transportation and fractionation assets that help support the feedstock needs of ConocoPhillips' refineries.

Other assets being retained include a 40 percent interest in a natural gas liquids fractionator in Conway, Kan.; a 92 percent interest in the 2.4 BCFD Empress natural gas processing plant and fractionation facilities in Alberta, Canada; and a 39 percent interest in Phoenix Park Gas Processor Limited in Trinidad. Phoenix Park operates a 1.4 BCFD gas processing plant and fractionator and markets NGL in the Caribbean region and along the U.S. Gulf Coast.

Chemicals

Operational Excellence Continues

Adam Rubalcaba works in the drumming department at the Chevron Phillips Chemical Company LP plant in Borger, Texas. The Borger plant produces organosulfur chemicals, Ryton® polyphenylene sulfide resins, specialty fuels, high-purity hydrocarbons and specialty solvents.

ConocoPhillips' Chemicals segment consists of its 50 percent interest in the joint-venture company, Chevron Phillips Chemical Company LLC (CPChem). The Chemicals segment posted net income of $7 million in 2003, compared with a loss of $14 million for 2002. The chemicals industry has been operating in an adverse economic environment over the past three-and-a-half years. During this time, CPChem has continued to focus on operational excellence, cost management, capital stewardship and selected growth opportunities. CPChem is well positioned as worldwide chemical markets gradually improve.

CPChem posted significant improvement in its 2002 safety results and continued that improvement throughout 2003. The current-year safety results were the best since formation of the company in mid-2000.

"Safety is our top priority," says Jim Gallogly, president and chief executive officer of CPChem. "We have continuously improved our safety record and are now ranked among the safest companies in the petrochemical industry."

CPChem's operational reliability also has been excellent with year-over-year improvement. "Operational excellence — running safely and reliably — is a key factor to profitability in bottom-of-the-cycle market conditions," says Gallogly.

CPChem is laying a solid foundation for future growth with its expansion into feedstock-advantaged locations, particularly in the Middle East. An existing aromatics complex in Al Jubail, Saudi Arabia, began production in 1999. Saudi Chevron Phillips Company (SCP), a 50-percent joint venture between CPChem and Saudi Industrial Investment Group, owns and operates the facility. A planned expansion project calls for the construction of styrene and propylene facilities on a site adjacent to the existing SCP facility. Final approval of the project will be requested in 2004, with startup expected in 2007.

A world-scale petrochemical complex in Mesaieed Industrial City, Qatar, designed to produce 1.1 billion pounds of ethylene, 1 billion pounds of polyethylene and 100 million pounds of 1-hexene annually, began production in 2003. The facility is owned and operated by Qatar Chemical Company Ltd. (Q-Chem), a joint venture between Qatar Petroleum (QP) (51 percent) and Chevron Phillips Chemical International Qatar Holdings LLC (Chevron Phillips Chemical Qatar), a subsidiary of CPChem (49 percent). The parties' plans also include the development of a second petrochemical complex in Mesaieed, Qatar (Q-Chem II), designed to produce polyethylene and normal alpha olefins on a site adjacent to the newly constructed Q-Chem complex. In a separate agreement with Atofina and Qatar Petrochemical Company, the parties established a joint venture to develop an ethane cracker in northern Qatar at Ras Laffan Industrial City. Final approval of these Q-Chem II projects is expected to be requested in 2005, with startup expected in 2008.

In addition to these international expansion projects, Chevron Phillips Chemical Company LP, a CPChem affiliate, made strategic investments in its U.S. assets by replacing older, higher-cost assets with new best-in-class facilities. A new 700 million-pound-per-year high-density polyethylene plant located at Chevron Phillips Chemical Company LP's Cedar Bayou facility in Baytown, Texas, became operational in 2003. It is the largest single-loop production system ever built. Chevron Phillips Chemical Company LP operates the plant, but it is owned equally with BP Solvay, and both companies share in the production equally.

In Port Arthur, Texas, Chevron Phillips Chemical Company LP began production of cyclohexane at a new world-scale facility in February 2004, and an existing smaller plant at the facility was shut down. This increases Port Arthur's cyclohexane capacity by approximately 590 million pounds per year.

"CPChem is focused on running safely and reliably, continuously improving our cost structure, and selectively growing in feedstock-advantaged areas," says Gallogly. "We have strong momentum heading into anticipated improving market conditions in the next several years."

Technologies Contribute Opportunities and Growth

ConocoPhillips maintains a disciplined, yet active approach to evaluate and develop emerging businesses and technology solutions that complement the company's base businesses.

Momentum toward integration of gas-to-liquids, power generation and technology solutions projects continued in 2003, as the company continuously worked toward solutions that fit within changing market, operations and technology environments. Numerous other opportunities also are being evaluated that will address changes in the industry and growth of the company's newest legacy assets. As part of a disciplined process and after thorough reviews, the company elected to shut down product development of carbon fibers, the diesel application of its S Zorb™ Sulfur Removal Technology (S Zorb), and wind power during 2003.

The Emerging Businesses segment had a net loss of $99 million in 2003, compared with a net loss of $310 million in 2002. The lower loss primarily resulted from a $246 million write-off in the third quarter of 2002 of purchased in-process research and development costs related to the merger.

"We are fortunate to have a portfolio of existing legacy projects in progressive stages of development to provide sustainable, profitable growth in our company for a long time," explains John Lowe, executive vice president of Planning, Strategy and Corporate Affairs. "The objectives of our Emerging Businesses are to provide us with an opportunity to enhance our existing business lines, as well as position ourselves for the future."

John E. Lowe, *Executive Vice President, Planning, Strategy and Corporate Affairs*

"Our process is to screen new opportunities and fund those that show promise for a competitive advantage in our key businesses or provide long-term promise," says Lowe. "This discipline contributed to our successful performance in 2003, and will help position the company for success in the future."

Technology Solutions Offers Clean Fuels Options

The company licenses several technologies, including the newly acquired E-Gas gasification technology — an environmentally friendly technology that uses petroleum coke or coal as fuel to create a natural-gas equivalent and produce electricity, according to Brian Evans, manager of technology solutions. "As one of the world's largest producers of coke, E-Gas offers a way to use a low-cost feedstock to produce a high-value product," says Evans.

In addition, the company licenses and has leading technology positions in petroleum coking and hydrofluoric (HF) alkylation.

Internally, ConocoPhillips is using its proprietary S Zorb gasoline sulfur removal technology at the Ferndale, Wash., refinery, where a new S Zorb unit was constructed and started up in 2003 on time and under budget. Gasoline from the 92,000 barrel-per-day refinery is now in compliance with increasingly stringent governmental regulations ahead of requirements coming in 2005 and 2006. S Zorb for gasoline also will be used in the company's 252,000 barrel-per-day Lake Charles, La., refinery.

Gas-to-Liquids Moving Ahead in the Middle East

Construction was completed and production started at the company's new 400 barrel-per-day gas-to-liquids (GTL) demonstration plant at the Ponca City, Okla., refinery. The Ponca City GTL plant will establish the commercial viability of the new technology, according to Jim Rockwell, manager of GTL.

A worker prepares to install a natural gas flow meter at the 730-megawatt Immingham power plant under construction next to ConocoPhillips' Humber refinery in the United Kingdom.

"GTL has been an accelerated technology development for ConocoPhillips," says Rockwell. "Research was started in 1997 toward this successful next step to acquire design data for a commercial-scale plant."

The success of the Ponca City GTL project led to the signing of a Statement of Intent with the State of Qatar to start pre-front-end engineering and design studies for construction of two 80,000 barrel-per-day GTL plants. First production from the Qatar GTL plants is anticipated in 2009-2010.

U.K. Power Plant Ready for Startup

The focus of ConocoPhillips' power business is on developing integrated projects in support of the company's Exploration and Production and Refining and Marketing strategies and business objectives. The company's new Immingham power plant at the Humber refinery in North Lincolnshire, England, will come onstream in 2004, with the expectation of becoming fully operational at midyear, according to Mike Swenson, manager of power, midstream gas and water.

This 730-megawatt cogeneration plant will supply steam and electricity to the Humber refinery. Excess steam will go to a neighboring refinery and excess electricity will be fed into the country's national grid. The plant also will have the design capacity to provide power and heat to other companies in the area.

Leveraging New Technologies for Future Growth

Understanding future energy issues and opportunities is a critical role for emerging technologies at ConocoPhillips. In 2003, the company studied a number of new ideas that will feed the technology development pipeline and potentially lead to new business opportunities, explains Ann Oglesby, manager of emerging technologies.

"The company's strategic direction in emerging technologies presently includes five areas of emphasis," says Oglesby. "By adhering to a disciplined process for staged development, we are able to manage a dynamic project portfolio across these emphasis areas."

The five areas of emphasis include: increased hydrocarbon recovery and access to new reserves; hydrocarbon processing and upgrading; petroleum coke upgrading and new carbon forms; byproducts and emissions management; and advanced fuels, including renewables.

"At all times, we are examining numerous options to leverage technology for the benefit of our current businesses and future growth," says Oglesby.

Commercial

Extracting Maximum Value from Our Assets

Commercial employees Paul Dudka, Ed Nadler, Felecia Moore and Denise Gaines support the buying and selling of commodities like crude oil, natural gas, refined products and electric power at ConocoPhillips' trading office in Houston. Open floor plans at the company's trading offices facilitate the sharing of critical market information among employees.

The Commercial organization continued to build a solid foundation for future growth in 2003. With offices in Houston, London, Singapore and Calgary, Commercial manages the company's dynamic marketing, supply and trading needs around the clock in markets worldwide. In 2003, consistent global measurement and risk management processes were implemented, and significant enhancements to trading and transactional systems were initiated.

"We're just scratching the surface of capturing the significant commercial value available from our large, global asset base," says Philip Frederickson, executive vice president of Commercial. "We have the potential to significantly grow our contribution and improve the returns of both the Exploration and Production (E&P) and Refining and Marketing businesses."

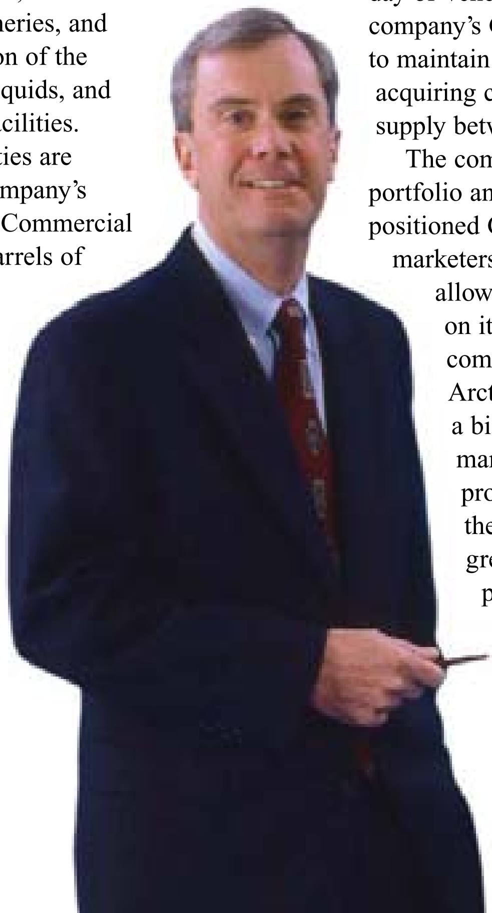
Commercial helps ConocoPhillips realize the maximum value for its crude oil and natural gas production, while minimizing the cost of crude oil, feedstocks and fuel for the company's 18 refineries, and efficiently managing disposition of the refined products, natural gas liquids, and power produced at company facilities.

Logistics and trading activities are globally integrated with the company's business segments. Each year, Commercial moves more than 2.5 billion barrels of crude oil and refined products and 3.5 trillion cubic feet of natural gas. With such a large system, an upgrade of only a few cents per barrel of oil equivalent can add hundreds of millions of dollars of additional profitability for the company.

"We perform a variety of services that create value for the company," says Frederickson, "including cost-effectively managing the procurement of crude oil and feedstocks for the company's refineries, arranging for transportation of these commodities, inventory management, and price risk management. We focus on optimizing the global system — as opposed to individual assets — extracting value from the many alternatives available to us across our asset base."

Commercial employees use their knowledge of markets and the company's assets to mitigate the effects of supply disruptions, such as the one that resulted from a labor strike in Venezuela in late 2002 and early 2003. Almost overnight, ConocoPhillips was temporarily without 225,000 barrels per day of Venezuelan crude oil that normally feeds two of the company's Gulf Coast refineries. Commercial acted quickly to maintain supply to these refineries by economically acquiring crude oil from other sources and optimizing supply between six of ConocoPhillips' U.S. refineries.

The company's North American natural gas production portfolio and third-party gas marketing business has positioned ConocoPhillips as one of the top four gas marketers in the United States. This market position allows the company to maximize the value it receives on its natural gas production while positioning the company to support future E&P projects, such as Arctic gas and liquefied natural gas imports. "Being a bigger player gives us greater access to more markets where we can sell our increased gas production from new projects coming online over the next few years," explains Frederickson. "Having greater market access has been a positive selling point with our co-venturers in these projects."

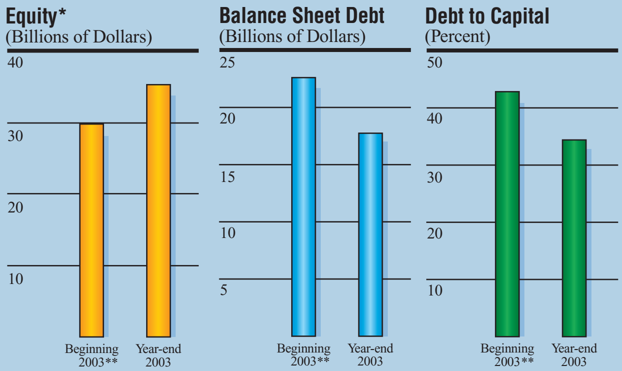


Philip L. Frederickson, *Executive Vice President, Commercial*

Financial Strategy

Building Strength Through Financial Discipline

Debt Ratio Improvement



** Includes common stockholders' equity and minority interest.*
*** Effective Jan. 1, 2003, the company adopted required accounting changes which reduced equity and increased debt balances by $0.4 billion and $2.8 billion, respectively.*

Debt as a percent of capital dropped to 34 percent at the end of 2003. The company's total debt and equity at year-end were $17.8 billion and $35.2 billion, respectively. The company's strategic plans include further balance sheet improvement, reflecting the company's commitment to financial discipline.

ConocoPhillips made significant progress toward strengthening its balance sheet in 2003. Robust cash flows from the company's operations, as well as proceeds of $2.7 billion from asset sales, helped ConocoPhillips reduce debt by $4.8 billion in 2003, including impacts from accounting changes.

"Lowering the debt is an important step toward achieving our goal of a debt-to-capital ratio in the low 30 percent range and improving our credit rating," says John Carrig, executive vice president, Finance, and chief financial officer. "While paying down debt is important, we're also making sure we have funds available to pursue new opportunities as they become available."

During 2003, the company adopted Financial Accounting Standards Board Interpretation No. 46 (FIN 46), "Consolidation of Variable Interest Entities," for synthetic leases and other financing structures. This resulted in increasing the company's total debt from $19.8 billion at the end of 2002 to $22.6 billion as of the beginning of 2003. The company's total debt was $17.8 billion at the end of 2003.

"In spite of an increase in debt of $2.8 billion associated with the FIN 46 accounting changes, we're still below the level that we expected to be with regard to our debt balance," says Carrig. "That's due in part to good commodity price performance and asset sales. It also reflects that we ran our operations well and delivered on the capture of synergies from the merger."

The company's debt-to-capital ratio was 34 percent at the end of 2003, and it is expected to further decrease in 2004. "Our objective is to continue to improve this ratio through positive cash flows from operations, continued synergy capture and additional proceeds from asset sales," says Carrig.

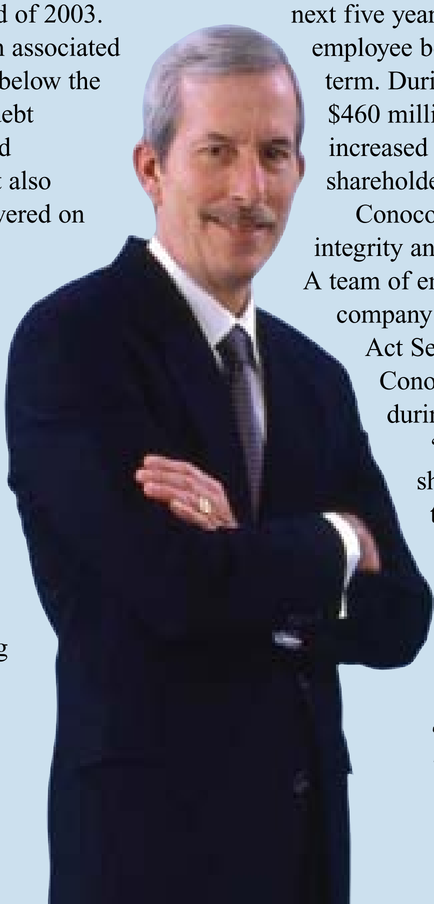
ConocoPhillips' 2004 capital budget is $6.9 billion, including about $0.5 billion in capitalized interest and $0.4 billion in minority interest. The 2004 budget is in line with the company's disciplined approach toward spending while supporting the strategy of growing its Exploration and Production (E&P) segment.

Seventy-eight percent of the 2004 capital budget — approximately $5.4 billion — is dedicated to E&P. Much of that funding will support the development of large, legacy projects that will provide long-term, attractive returns. Nineteen percent of the capital budget — approximately $1.3 billion — will go to Refining and Marketing, including funds for new clean fuels projects at the company's refineries. The remainder of the total company budget will go to Emerging Businesses and for general corporate purposes.

In addition to funding capital programs, ConocoPhillips plans to continue in its commitment to provide pension and employee benefit funding of $350 million annually over the next five years to ensure qualified U.S. pension and employee benefit plans are supported for the long term. During 2003, the company contributed $460 million to these plans. The company also increased its quarterly dividend rate to shareholders by 7.5 percent in 2003.

ConocoPhillips applies discipline to the integrity and transparency of its financial results. A team of employees is dedicated to ensuring the company is in compliance with Sarbanes-Oxley Act Section 404 regulations that ConocoPhillips is required to implement during 2004.

"Our financial performance in 2003 shows that our disciplined approach toward improving total shareholder return is working," says Carrig. "We're making great progress in improving the balance sheet while building momentum for the future."



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

corporate review

In 2003, ConocoPhillips' corporate groups led efforts to define the company's commitment to sustainable development, expand employee development programs, ensure compliance with laws and regulations, and provide technology and support to business units around the world. The corporate groups fill a vital role in the organization — ensuring ConocoPhillips' operating groups have the right people, technologies and processes they need to be successful.

The Endeavour-class tanker Polar Resolution docks in Valdez, Alaska, to load a shipment of North Slope crude oil. Double-hulled tankers like the Resolution help ConocoPhillips fulfill its sustainable development commitment to minimize the environmental impact of its operations. ConocoPhillips' entire fleet of tankers will be double-hulled by 2008.

Global Systems and Services

Delivering World-Class Services and Support

Shelley Rigdon-Dow and Dave Baldwin, both employees with the global information systems group in Bartlesville, Okla., test new software on a server before installing it on the company's network. The group is looking at ways to automate server maintenance tasks, giving the group's employees more time to help business units with other innovations.

Global Systems and Services (GSS) made significant progress in 2003 in consolidating services, leveraging computing and financial systems and streamlining processes, while supporting ConocoPhillips' businesses around the world.

"GSS is helping enable the rest of the corporation to capture greater business value, additional synergies, and operating and process efficiencies throughout the company," says Gene Batchelder, senior vice president, Services, and chief information officer. "The vision for GSS employees is to lay a foundation that, ultimately, will help empower all of our employees and businesses to maximize performance."

Comprised of aviation, facilities management, financial services, information services and procurement, GSS offers a wide realm of support, delivering services to all groups across the company. GSS efforts in 2003 provided millions of dollars in business value, through efforts such as:

- Converging the domestic lubricants business to a single set of systems and platforms, resulting in optimized production planning, improved sourcing contracts, and reduced operating expenses;
- Partnering and championing with business units to gain procurement savings through improved supplier management and better commercial relations;
- Eliminating redundant systems by providing an integrated global platform for businesses to conduct financial, materials management, and plant maintenance activities;
- Integrating telecommunications networks to create a single global network and provide cost efficiencies through optimization of carrier contracts; and
- Consolidating data center operations, allowing for maximum leverage of support, service contracts, and facilities usage.

"As we put new systems and processes into place during 2003 and 2004, we want to help ConocoPhillips' businesses take advantage of those services and exploit the knowledge, technology and capabilities of GSS," says Batchelder.

During the initial planning stages for the merger, groups within GSS recognized that the size of the company — the large number of employees, locations and functions — would present challenges in delivering new systems and services. Despite those challenges, GSS remains ahead of schedule on its major systems integration projects and plans further globalization and streamlining of service delivery processes throughout ConocoPhillips in 2004.

While GSS strengthens relationships with the staffs and businesses it supports internally, maintaining strong relationships with its business partners, vendors and key consultants also remains a top priority.

Says Batchelder, "As GSS continues putting the technology, processes and other major components in motion, we want to continue exceeding synergy targets, completing transitions ahead of schedule, and delivering world-class services to ConocoPhillips."

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

Legal

Furthering Open, Trustworthy Relationships

ConocoPhillips employees Willette DuBose and Stephen Chung work for the Legal department in Houston. They are part of a team that is responsible for ensuring the company is compliant with environmental laws and regulations.

ConocoPhillips can grow and add value only by pursuing open and trustworthy relationships with investors, partners, customers, employees, communities, governments and other stakeholders, according to Steve Gates, senior vice president, Legal, and general counsel. Says Gates, "People should want to associate with our company, not only because of our capabilities, but because of our integrity and reputation. This can be a powerful competitive advantage."

Operating Ethically Everywhere

Ethical business behavior is a condition of employment at ConocoPhillips. "We realize that the motivation of an employee to set a positive example should grow out of a personal value system," explains Gates. "The company's responsibility is to communicate clear performance expectations and provide education, training and guidance on ethical and legal compliance questions."

All employees are expected to have a working knowledge of the company's Code of Business Ethics and Conduct, which provides guidance on corporate policies, principles and procedures. The code also requires employees to complete an annual certification of personal compliance. The company's internal auditor serves as the chief ethics officer.

Other facets of the ethics and compliance program include management commitment, training for general and specialized situations, ongoing communications, counseling, violation reporting mechanisms, and in the case of potential code violations, investigation resources and appropriate disciplinary actions.

The company's compliance committee, composed of senior executives and lawyers, provides regular reports to the chief executive officer (CEO), as well as the board of directors' audit and compliance committee, regarding the results of annual code certifications, the state of compliance activities and handling of reports of violation.

Stephen F. Gates,
Senior Vice President,
Legal, and General Counsel

Governing with Vigorous Oversight

The audit and compliance committee of the board meets regularly with company management, the company's independent auditors and the internal auditor to review accounting policies, internal controls, financial statements and disclosures, financial reporting practices, significant corporate risk exposures, and governance issues including ethics code and legal compliance.

The ConocoPhillips board of directors is composed predominately of outside directors who provide independent and objective oversight of the company's policies, practices and performance. ConocoPhillips' board consists of 14 non-employee directors and two employee directors — the board chairman and the president and CEO.

Board members are nominated by the board's committee on directors' affairs on the basis of personal character, judgment, diversity, age, skills, financial literacy, and experience in areas that are relevant to the company's business and its relationships with various stakeholders. The current board is drawn from a variety of fields including technology, environmental protection, education, international affairs, engineering, aviation, finance, investing and resource development.

"Directors provide independent perspective and ask critical questions representing the interests and concerns of shareholders as well as other key stakeholders," says Gates. "The board's diversity and depth of experience, combined with the integrity of its individual members, provide a key resource in assuring our reputation and commitment to compliance."

Health, Safety and Environment

Committed to Sustainable Development

In 2003, ConocoPhillips outlined its position on sustainable development. At the heart of this position are nine commitments that lead to measurable actions. The company also developed a position on climate change, a key issue of concern to stakeholders.

For ConocoPhillips, sustainable development is a commitment to conduct business to promote economic growth, a healthy environment and vibrant communities, now and into the future.

"We take pride in doing the right things in the right way," says Bob Ridge, vice president of Health, Safety and Environment (HSE). "As we incorporate sustainable development into our business planning, we draw from the many pockets of excellence in our company around environmental, social and broader economic issues."

For example, ConocoPhillips is increasing the availability of cleaner motor fuels through products such as S Zorb™ Sulfur Removal Technology, which provides a cost competitive means for reducing sulfur content in gasoline to well below 10 parts per million, easily meeting regulations in the United States and Europe.

ConocoPhillips strives to be energy efficient when designing new installations and takes steps wherever possible to avoid the venting or flaring of gases. Designing the company's new liquefied natural gas facility planned for Darwin, Australia, to reduce flaring means a higher equipment cost, but the company will benefit from lower energy costs and added income derived from selling captured gas that might have been flared in more traditional designs.

Before beginning a new construction project, ConocoPhillips carries out social and environmental impact surveys and discusses plans with local stakeholders to ensure that development is in tune with their needs. Engaging in this upfront planning for the Surmont oil sands project in Alberta, Canada, has helped build local communities' confidence in the company and facilitated the permitting and approval process for the project. It also resulted in locating the project away from sensitive ecosystems and identifying ways to support local employment needs.

"Sustainable development provides an overarching framework for how we work," says Ridge. "That includes taking pragmatic action on key stakeholder concerns, such as climate change. While the debate on the science behind climate change continues, ConocoPhillips has made a proactive commitment to reducing our greenhouse gas emissions in a way that is aligned with both environmental and economic objectives."

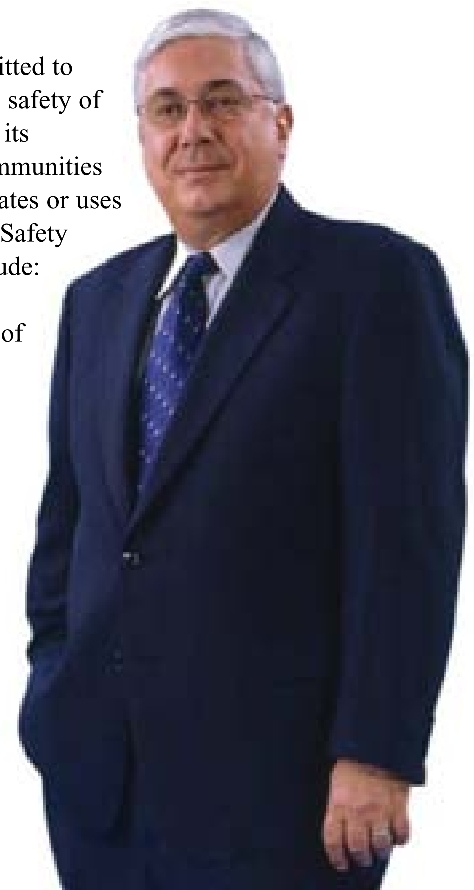
ConocoPhillips has established a sound measurement system and completed an inventory of greenhouse gas emissions based on 2002 data, focusing on carbon dioxide and methane, which are the major contributors to total greenhouse gas emissions from crude oil and natural gas operations. This provides a benchmark for comparison as ConocoPhillips develops a comprehensive future program for cost-effective management of greenhouse gases.

"Articulating our positions on sustainable development and climate change is just the first step," explains Ridge. "In 2004, we will prioritize issues, establish plans for action with clear goals and monitor our performance in order to deliver on our commitments."

Safety

ConocoPhillips is committed to protecting the health and safety of everybody who works at its facilities, lives in the communities where the company operates or uses the company's products. Safety milestones for 2003 include:

- Strengthening the companywide culture of safety by focusing on HSE management systems and targeted safety-improvement efforts.



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

ConocoPhillips promotes sustainable development in South Sumatra, Indonesia, by loaning money to farmers to start rubber tree plantations. Because rubber trees take five to six years to mature, the farmers also receive loans to plant banana trees that mature within months, providing a source of income until the rubber trees are ready to be "tapped." The program has assisted 100 farmers since it began in 2002.

ConocoPhillips employee Sean Helton and his son, Beau, pick up litter at Surfside Beach on the Texas Gulf Coast south of Houston. ConocoPhillips' Sweeny, Texas, refinery sponsors two beach cleanups every year as part of its environmental outreach program.

ConocoPhillips' employee total recordable rate (TRR) improved 23 percent compared with the full-year 2002 pro forma rate. Contractor TRR improved 20 percent for the same period. However, there were three employee fatalities and one contractor fatality during the year.

- Eight ConocoPhillips facilities received 26 safety awards from the National Petrochemical & Refiners Association.

Environment

Wherever ConocoPhillips operates, the company conducts business with respect and care for the environment and systematically manages risks to drive sustainable business growth. The company's environmental initiatives in 2003 resulted in:

- Reducing the number of significant liquid hydrocarbon spills (more than 100 barrels) by 33 percent and the amount of hydrocarbons spilled from these events by 55 percent, compared with pro forma 2002 performance.
- Certification of the entire U.K. Exploration and Production (E&P) organization operating in the North Sea under the internationally recognized ISO 14001 environmental management system. Other ConocoPhillips sites already certified include: E&P operations in China; the Humber refinery in the United Kingdom; the Alliance refinery in Belle Chasse, La.; and lubricants plants in Hartford, Ill., and Sulphur, La.
- Launching of the third Endeavour Class tanker, the *Polar Discovery*. With double hulls and other state-of-the-art environmental and safety features, the Endeavour Class is the most advanced class of tanker transportation. Two additional Endeavour Class tankers are scheduled for delivery, one each in 2004 and 2005.

Human Resources

Building on Our Commitment to People

Human Resources professionals Maria Jimenez, Tom Burley, Chris Nguyen and Tanya Kimbrough Smith transform talent management strategies into tangible opportunities for employee development and growth for ConocoPhillips people worldwide.

Building momentum takes talented, passionate people capable of recognizing and capturing opportunities that help the company succeed. “People are the lifeblood of ConocoPhillips,” says Carin Knickel, vice president of Human Resources. “Our commitment to people — and the heart of our people strategy — is creating the highest-performing environment where people and businesses thrive.”

Enabling People to See the Difference They Make

Employees want to know how to enable the company to succeed. ConocoPhillips recognizes the importance of connecting individuals to the company’s strategy.

“Around the globe, ConocoPhillips leaders meet face-to-face with employees to build a shared understanding of how everyone contributes to helping the company achieve success,” says Knickel. “A companywide focus on strategic objectives keeps employees engaged.”

Developing People for Success

“The company’s talent management philosophy extends from new employees to executives,” explains Knickel, “ensuring employees have the right talent, skills and experience to be successful.”

The SPIRIT Scholars program provides mentoring and scholarships to attract top talent to the company. After joining the company, employees engage in performance management processes to chart their growth and accomplishments in concert with the businesses. In one-on-one sessions, employees and managers craft their goals in alignment with business strategy, ensuring that everyone pulls in the right direction.

Rewarding Performance

At ConocoPhillips, when the company succeeds, employees benefit. The annual Variable Cash Incentive Program (VCIP) rewards employees when the company and their businesses reach specific performance and safety targets. The SPIRIT of Performance Awards and the special recognition program reward and celebrate individual and team achievements.

Says Knickel, “Our reward programs are linked closely to performance, enabling the company to recognize, reward and retain talented professionals integral to our success. We offer a competitive compensation and benefits package — including health-related benefits and programs that encourage healthful living while adding to the wealth and well-being of employees. Together, these programs motivate people who consistently deliver results.”

Carin S. Knickel,
Vice President, Human Resources

People-Driven Core Values

ConocoPhillips’ core values — Safety, People, Integrity, Responsibility, Innovation and Teamwork, reflect the company’s spirit and culture. “In particular, the People component of our SPIRIT values encompasses a diversity of heritages, experiences and ways of thinking,” adds Knickel. “Our value for people extends beyond the workplace into communities where employees participate in volunteer outreach activities. ConocoPhillips’ support of local cultures and communities strengthen the company’s reputation as a business partner of choice around the world.”

Listening to Employees

ConocoPhillips listens to and values employees’ opinions. The 2003 worldwide employee opinion survey returned a 74 percent participation rate, laying the groundwork for ongoing communication around performance and strategy.

Says Knickel, “We take employee feedback to heart and act upon it, such as holding leaders accountable to communicate with their employees more frequently and equipping them to do so. It’s through our commitment to people that ConocoPhillips maintains a fast-paced, winning environment that leads to business success.”

financial review

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

February 25, 2004

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, intentions, and resources 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," "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 60.

Results of Operations

Merger of Conoco and Phillips

On August 30, 2002, Conoco Inc. (Conoco) and Phillips Petroleum Company (Phillips) combined their businesses by merging with wholly owned subsidiaries of a new company named ConocoPhillips (the merger). The merger was accounted for using the purchase method of accounting, with Phillips designated as the acquirer for accounting purposes. Because Phillips was designated as the acquirer, its operations and results are presented in this annual report for all periods prior to the close of the merger. From the merger date forward, the operations and results of ConocoPhillips reflect the combined operations of the two companies.

Business Environment and Executive Summary

Our overall earnings depend primarily upon the profitability of our Exploration and Production (E&P) and Refining and Marketing (R&M) segments. Our earnings normally are less impacted by results from the Midstream, Chemicals and Emerging Businesses segments.

Crude oil and natural gas prices, along with refining margins, play the most significant roles in our profitability. These prices and margins are driven by market factors over which we have no control. However, from a competitive perspective, there are other important factors that 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. Consistently high utilization rates at our refineries, minimizing downtime in producing fields, and maximizing the development of our reserves all enable us to capture the value the market gives us in terms of prices and margins. Finally, our operations are conducted in a manner that emphasizes our environmental stewardship.
- **Controlling costs and expenses.** Since we cannot control the prices of the commodity products we sell, keeping our operating and overhead costs low, within the context of our commitment to safety and environmental stewardship, is a top priority. We monitor these costs using various methodologies that are reported to senior management monthly, on both an absolute-dollar basis and a per-unit basis. Low operating and overhead costs are critical to maintaining competitive positions in our industries, as such, cost control is a component of our variable compensation programs.
- **Selecting the appropriate projects in which to invest our capital dollars.** We participate in capital-intensive industries. As a result, we must often invest significant capital dollars to explore for new oil and gas fields, develop newly discovered fields, maintain existing fields, or continue to maintain and improve our refinery complexes. We invest in those projects that are expected to provide an adequate financial return on invested dollars. However, there are often long lead times from the time we make an investment to the time that investment is operational and begins generating financial returns. Our capital spending in 2003 totaled $6.2 billion, and we anticipate capital spending to be approximately $6.9 billion in 2004.
- **Evaluating 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 growth strategy 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.
- **Hiring, developing and retaining a talented workforce.** We want to attract, train, develop and retain individuals with the knowledge and skills to implement our business strategy and who support our values and ethics.

Many of our key performance indicators are shown in the statistical tables provided at the beginning of our operating segment sections that follow. These include crude oil and natural gas prices and production, natural gas liquids prices, refining capacity utilization, and refinery output. We also use the "return on capital employed" measure.

Other significant factors that can and/or do 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 decline significantly for long periods of time, or when a decision to dispose of an asset leads to a write-down to fair market value. Also, at times we invest large amounts of money in exploration blocks which, if exploratory drilling proves unsuccessful, could lead to material impairment of leasehold values.

- **Goodwill.** As a result of recent mergers and acquisitions, we have a significant amount of goodwill on our balance sheet. 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 affect on the company's profitability.
- **Tax jurisdictions.** As a global company, our operations are located in countries with different tax rates and fiscal structures. Accordingly, our overall effective tax rate can vary significantly between periods based on the "mix" of earnings within our global operations.

Segment Analysis

The E&P segment's results are most closely linked to crude oil and natural gas prices. These are commodity products, the prices of which are subject to factors external to our company and over which we have no control. We benefited from favorable crude oil prices in 2003, which contributed significantly to what we view as strong results from this segment in 2003. For a discussion of factors impacting crude oil and natural gas prices in 2003, as well as our view of the potential movement of these prices into 2004, see the "Outlook" section. At year-end 2003, we estimated that a $1 per barrel change in crude oil prices would have an estimated $170 million annual impact on net income. For natural gas, the corresponding impact is approximately $40 million for a 10 cent per thousand cubic feet price change.

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 30.3 percent equity investment in Duke Energy Field Services, LLC (DEFS). Higher natural gas liquids prices improved results from this segment in 2003. In early 2004, we approved the disposal of some of our non-DEFS Midstream assets located in the lower 48 states that are not associated with our E&P operations.

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. Refining margins in 2003 were much improved over 2002, resulting in improved R&M profitability. See the "Outlook" section for further discussion of refining margins in 2003 and our view of their potential movement into 2004. At year-end 2003, we estimated that a 25 cent per barrel change in refining margins would have an estimated $125 million annual impact on net income. For wholesale marketing margins, the corresponding impact is approximately $100 million for a 1 cent per gallon margin change. Our refineries operated at 94 percent of rated capacity in 2003, and our goal in 2004 is to operate at about the same level.

The Chemicals segment consists of our 50 percent interest in Chevron Phillips Chemical Company LLC (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. The chemicals and plastics industry has been in a cyclical downturn for the last several years. In this difficult market environment, CPChem has placed great emphasis on safety, cost control and managing its capacity utilization. In addition, CPChem is investing in feedstock-advantaged areas in the Middle East with access to large, growing markets, such as Asia. With its low cost structure, we feel CPChem is well positioned to benefit from improved margins when the chemicals industry emerges from its downturn.

The Emerging Businesses segment represents our investment in new technologies or businesses outside our normal scope of operations. We do not expect the results from this segment to be material to our consolidated results. However, the businesses in this segment allow us to support our primary segments by staying current on new technologies that could become important drivers of profitability in future years.

At December 31, 2003, we had a debt-to-capital ratio of 34 percent. We have made a priority of using funds available after paying dividends and capital spending to reduce debt. We reduced our debt by $4.8 billion in 2003. We feel that by lowering our debt-to-capital ratio over the next several years to about 30 percent, we can improve our cost of capital and further position ourselves for growth opportunities in the future.

Consolidated Results

Years Ended December 31	Millions of Dollars		
	2003	2002	2001
Income from continuing operations	**$4,593**	698	1,601
Income (loss) from discontinued operations	**237**	(993)	32
Cumulative effect of accounting changes	**(95)***	—	28
Net income (loss)	**$4,735**	(295)	1,661

**Includes a $107 million charge related to discontinued operations.*

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

Years Ended December 31	Millions of Dollars		
	2003	2002	2001
Exploration and Production (E&P)	**$4,302**	1,749	1,699
Midstream	**130**	55	120
Refining and Marketing (R&M)	**1,272**	143	397
Chemicals	**7**	(14)	(128)
Emerging Businesses	**(99)**	(310)	(12)
Corporate and Other*	**(877)**	(1,918)	(415)
Net income (loss)	**$4,735**	(295)	1,661

**Includes income (loss) from discontinued operations.*

2003 vs. 2002

Net income was $4,735 million in 2003, compared with a net loss of $295 million in 2002. The improved results in 2003 were primarily due to:

- Increased E&P and R&M production volumes as a result of the merger;
- Higher crude oil, natural gas, and natural gas liquids prices in our E&P segment;
- Improved refining and marketing margins in our R&M segment;
- Lower impairments and lease loss accruals related to discontinued operations; and
- Lower merger-related expenses in 2003, compared with 2002.

See the “Segment Results” section for additional information on our E&P and R&M results, as well as our other reporting segments.

2002 vs. 2001

We incurred a net loss of $295 million in 2002, compared with net income of $1,661 million in 2001. The decrease was primarily attributable to recognizing impairments and loss accruals totaling $1,077 million after-tax associated with our retail and wholesale marketing operations that were classified as discontinued operations in late 2002, as well as merger-related costs totaling $557 million after-tax. Also negatively impacting results for 2002 were other asset impairments totaling $192 million after-tax, lower refining margins, lower natural gas sales prices, decreased equity earnings from Duke Energy Field Services, LLC (DEFS), and higher interest expense. These factors were partially offset by improved results from Chemicals and higher production volumes in E&P after the merger.

Income Statement Analysis

2003 vs. 2002

The merger affects the comparability of the 2003 and 2002 periods. 2003 includes a full year of ConocoPhillips’ operations, while 2002 includes only four months of combined operations. Prior to August 30, 2002, our results reflect Phillips’ operations only. Accordingly, the merger significantly increased:

- Sales revenues and purchase costs due to higher volumes of products being bought and sold;
- Equity earnings due to an increased number of equity affiliates;
- Production and operating expenses and selling, general and administrative expenses due to the increased size and scope of operations following the merger, partially offset by lower merger-related costs in 2003;
- Depreciation, depletion and amortization due to the increased depreciable asset base;
- Taxes other than income taxes due to higher gasoline sales, production volumes and property and payroll taxes; and
- Interest and debt expense due to higher debt levels following the merger.

In addition to the merger impact, sales and other operating revenues and purchase costs increased because of higher prices for key products such as crude oil, natural gas, automotive gasoline and distillates. These are commodity products and their price levels are determined by market factors.

Our share of earnings from affiliates acquired in the merger accounted for the majority of the increase in the equity earnings. Of these, the E&P joint ventures in Canada (Petrovera) and Venezuela (Petrozuata), along with CFJ Properties in our R&M segment, provided the largest equity earnings. On February 18, 2004, we sold our interest in the Petrovera joint venture. Of the equity affiliates held prior to the merger, our equity earnings from DEFS improved on higher natural gas liquids prices, and our earnings from Hamaca, an E&P heavy-oil joint venture in Venezuela, increased due to higher crude oil production.

A higher net gain on asset sales was primarily responsible for the increase in other income in 2003. During 2003 we sold several E&P operations that did not fit into our long-term growth strategy. In addition, 2003 included gains attributable to insurance demutualization benefits. See the Corporate and Other section of “Segment Results” for additional information on these insurance benefits.

Selling, general and administrative expenses in 2002 included a $246 million charge for the write-off of in-process research and development costs acquired in the merger. The absence of such a significant charge in the 2003 period reduced the impact of the merger on this line item.

Property impairments increased by $75 million in 2003, compared with 2002. The 2003 impairments were recorded as a result of asset status changes from held-for-use to held-for-sale, producing properties that failed to meet recoverability tests, and tax law changes in Norway affecting asset removal costs. During 2002, property impairments were triggered by asset dispositions and the impairment of tradenames. See Note 12 — Property Impairments, in the Notes to Financial Statements, for additional information.

Accretion on discounted liabilities increased $123 million in 2003, reflecting accretion expense on environmental liabilities assumed in the merger and discounted obligations associated with the retirement and removal of long-lived assets that became effective January 1, 2003, with the adoption of Statement of Financial Accounting Standards (SFAS) No. 143, “Accounting for Asset Retirement Obligations.” See Note 2 — Changes in Accounting Principles, in the Notes to Financial Statements, for additional information on SFAS No. 143.

In addition to the merger impact, interest and debt expense also increased in 2003 because of the adoption of Financial Accounting Standards Board (FASB) Interpretation No. 46, “Consolidation of Variable Interest Entities,” (FIN 46). The adoption of FIN 46 for variable interest entities involving synthetic leases and certain other financing structures, effective January 1, 2003, resulted in increased balance sheet debt, which resulted in higher interest expense in 2003. See Note 2 — Changes in Accounting Principles, and Note 14 — Debt, in the Notes to Consolidated Financial Statements, for additional information.

During 2003, we recognized a $28 million gain on subsidiary equity transactions related to our E&P Bayu-Undan development in the Timor Sea. See Note 7 — Subsidiary Equity Transactions, in the Notes to Consolidated Financial Statements, for additional information.

Our effective tax rate in 2003 was 45 percent, compared with 67 percent in 2002. The lower effective tax rate in 2003 primarily was the result of a higher proportion of income in lower-tax-rate jurisdictions and the one-time impact of tax law changes in certain international jurisdictions. Contributing to the higher effective tax rate in 2002 was a write-off of in-process research and development costs, as well as the partial impairment of an exploration prospect, both without corresponding tax benefits in 2002.

Our discontinued operations had income of $237 million in 2003, compared with a net loss of $993 million in 2002. The net loss in 2002 reflected charges totaling $1,008 million after-tax related to the impairment of properties, plants and equipment; goodwill; intangible assets; and provisions for losses associated with various operating lease commitments. For additional information about our discontinued operations, see Note 4 — Discontinued Operations, in the Notes to Consolidated Financial Statements.

We adopted SFAS No. 143 effective January 1, 2003, resulting in the recognition of a benefit of $145 million for the cumulative effect of this accounting change. Also effective January 1, 2003, we adopted FIN 46 for variable interest entities involving synthetic leases and certain other financing structures created prior to February 1, 2003. This resulted in a charge of $240 million for the cumulative effect of this accounting change. Together, these resulted in a net charge of $95 million. For additional information on these accounting changes, see Note 2 — Changes in Accounting Principles, in the Notes to Consolidated Financial Statements.

2002 vs. 2001

In addition to the merger of Conoco and Phillips on August 30, 2002, ConocoPhillips closed on the $7 billion acquisition of Tosco Corporation on September 14, 2001. Together, these transactions significantly increased operating revenues; equity earnings; other income; purchase costs; operating expenses; selling, general and administrative expenses; depreciation, depletion and amortization; taxes other than income taxes; accretion on discounted liabilities; and interest and debt expense in 2002, compared with 2001.

Restructuring Accruals

As a result of the merger, we began a restructuring program in September 2002 to capture the benefits of combining Conoco and Phillips by eliminating redundancies, consolidating assets, and sharing common services and functions across regions. We expect the restructuring program to be completed by the end of the first quarter of 2004. From September 2002 through December 31, 2003, approximately 3,900 positions worldwide had been identified for elimination. Of this total, approximately 3,000 employees had been terminated by December 31, 2003. The information in Note 5 — Restructuring, in the Notes to Consolidated Financial Statements, is incorporated herein by reference.

Segment Results

E&P

	2003	2002	2001
	Millions of Dollars		
Net Income			
Alaska	**$ 1,445**	870	866
Lower 48	**929**	286	476
United States	**2,374**	1,156	1,342
International	**1,928**	593	357
	$ 4,302	1,749	1,699
	Dollars Per Unit		
Average Sales Prices			
Crude oil (per barrel)			
United States	**$ 28.85**	23.83	23.57
International	**28.27**	25.14	24.16
Total consolidated	**28.54**	24.38	23.77
Equity affiliates	**18.58**	18.41	12.36
Worldwide	**27.47**	24.07	23.74
Natural gas — lease (per thousand cubic feet)			
United States	**4.62**	2.75	3.56
International	**3.71**	2.79	2.60
Total consolidated	**4.07**	2.77	3.23
Equity affiliates	**4.44**	2.71	—
Worldwide	**4.07**	2.77	3.23
Average Production Costs Per Barrel of Oil Equivalent			
United States	**$ 5.89**	5.66	5.52
International	**4.25**	3.99	2.70
Total consolidated	**5.00**	4.94	4.60
Equity affiliates	**4.72**	4.38	2.74
Worldwide	**4.98**	4.92	4.60
Finding and Development Costs Per Barrel of Oil Equivalent*			
United States	**$ 9.30**	7.46	5.15
International	**4.54**	5.09	6.80
Worldwide	**5.35**	5.57	5.97

Includes our share of equity affiliates.

	2003	2002	2001
	Millions of Dollars		
Worldwide Exploration Expenses			
General administrative; geological and geophysical; and lease rentals	**$ 301**	285	207
Leasehold impairment	**133**	146	51
Dry holes	**167**	161	48
	$ 601	592	306

	2003	2002	2001
	Thousands of Barrels Daily		
Operating Statistics			
Crude oil produced			
Alaska	**325**	331	339
Lower 48	**54**	40	34
United States	**379**	371	373
European North Sea	**290**	196	136
Asia Pacific	**61**	24	17
Canada	**30**	13	1
Other areas	**72**	43	34
Total consolidated	**832**	647	561
Equity affiliates	**102**	35	2
	934	682	563
Natural gas liquids produced			
Alaska	**23**	24	25
Lower 48	**25**	8	1
United States	**48**	32	26
European North Sea	**9**	8	7
Canada	**10**	4	—
Other areas	**2**	2	2
	69	46	35
	Millions of Cubic Feet Daily		
Natural gas produced*			
Alaska	**184**	175	177
Lower 48	**1,295**	928	740
United States	**1,479**	1,103	917
European North Sea	**1,215**	595	308
Asia Pacific	**318**	137	51
Canada	**435**	165	18
Other areas	**63**	43	41
Total consolidated	**3,510**	2,043	1,335
Equity affiliates	**12**	4	—
	3,522	2,047	1,335

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

	Thousands of Barrels Daily		
Mining operations			
Syncrude produced	**19**	8	—

2003 vs. 2002

The E&P segment explores for and produces 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, 2003, our E&P operations were producing in the United States, the Norwegian and U.K. sectors of the North Sea, Canada, Nigeria, Venezuela, offshore Timor Lesté in the Timor Sea, offshore Australia, offshore China, offshore the United Arab Emirates, offshore Vietnam, Russia, and Indonesia.

Net income from the E&P segment increased 146 percent in 2003, compared with 2002. The improvement reflects higher production volumes, primarily due to the merger; higher crude oil and natural gas prices; and an increased net gain on asset sales. These items were partially offset by higher production and operating expenses; depreciation, depletion and amortization; and taxes other than income taxes, all the result of the larger size and scope of our operations following the merger.

In addition, 2003 included benefits of $233 million in our international E&P operations from changes in income tax and site restoration laws, as well as an equity realignment of certain Australian operations. Also, the cumulative effect of the adoption of SFAS No. 143 and the adoption of FIN 46 for variable interest entities involving synthetic leases and certain other financing structures increased E&P's net income by $142 million in 2003.

Our average worldwide crude oil sales price was $27.47 per barrel in 2003, compared with $24.07 in 2002. We also benefited from higher natural gas prices in 2003, with our average worldwide price increasing from $2.77 per thousand cubic feet in 2002 to $4.07 in 2003. If crude oil and natural gas prices in 2004 do not remain at the historically strong levels experienced in 2003, E&P's earnings will be negatively impacted in 2004. See the "Outlook" section for additional discussion of crude oil and natural gas prices.

ConocoPhillips' proved reserves at year-end 2003 were 7.85 billion barrels of oil equivalent, a slight increase over 7.81 billion barrels at year-end 2002. Our Canadian Syncrude mining operations had an additional 265 million barrels of proved oil sands reserves at the end of 2003, compared with 272 million barrels at year-end 2002.

2002 vs. 2001

Net income from the E&P segment increased 3 percent in 2002, compared with 2001. Although E&P benefited from four months of increased production volumes in 2002 following the merger, this increase was mostly offset by lower natural gas sales prices, higher exploration expenses, and the unfavorable $24 million impact of a tax law change in the United Kingdom. Our average worldwide crude oil sales price was $24.07 per barrel in 2002, a 1 percent increase over $23.74 in 2001. Our average worldwide natural gas price in 2002 was $2.77 per thousand cubic feet, a 14 percent decrease from $3.23 in 2001.

Our proved reserves at year-end 2002 were 7.81 billion barrels of oil equivalent, a 52 percent increase over year-end 2001's 5.13 billion barrels of oil equivalent. The increase was attributable to the merger.

U.S. E&P

2003 vs. 2002

Net income from our U.S. E&P operations increased 105 percent in 2003, compared with 2002. Net income from our Alaskan operations increased $575 million in 2003. The improvement in Alaska reflects higher crude oil prices, and a net $143 million benefit from the cumulative effect of adopting SFAS No. 143 and FIN 46, partially offset by slightly lower crude oil production volumes. The West Coast price of our Alaskan crude oil production increased 22 percent in 2003, from $23.75 per barrel in 2002 to $28.87 per barrel in 2003. Normal field declines and some operating interruptions in 2003 were mostly offset by increased production from the Borealis satellite field, the new Kuparuk Palm drill site, and Alpine, which enabled us to experience only a slight decrease in our Alaska crude oil production rate in 2003.

Our E&P Lower 48 net income increased $643 million in 2003, primarily because of increased natural gas production and sales prices, as well as, to a lesser extent, higher crude oil production and prices. U.S. Lower 48 natural gas prices increased 71 percent in 2003. Our increased production volumes in the Lower 48 mainly were the result of the merger, partially offset by the impact of asset dispositions. We continued our Lower 48/Gulf of Mexico asset rationalization program in 2003, which resulted in the sale of properties that did not fit into our long-term growth strategy. As planned, we are exiting the shallow water areas of the Gulf of Mexico. The Lower 48 operations recognized a net $1 million charge from the cumulative effect of adopting SFAS No. 143 and FIN 46 effective January 1, 2003.

2002 vs. 2001

Net income from U.S. E&P operations decreased 14 percent in 2002, compared with 2001. Although net income for 2002 benefited from four months of increased production volumes following the merger, this increase was more than offset by lower natural gas prices, lower production volumes in Alaska, and higher dry hole costs. Our U.S. average natural gas price in 2002 was 23 percent lower than in 2001.

Our U.S. crude oil production decreased slightly in 2002, while natural gas production increased 20 percent. The increase in natural gas production was mainly due to four months of production from fields acquired in the merger. The merger impact on total crude oil production was offset by lower production in Alaska, which experienced normal field declines, along with operating interruptions at the Prudhoe Bay field.

International E&P

2003 vs. 2002

Net income from our international E&P operations increased 225 percent in 2003, compared with 2002. Increased production volumes following the merger accounted for the majority of the earnings improvement. Higher crude oil and natural gas prices contributed to the remaining increase.

International E&P's production on a barrel-of-oil-equivalent basis averaged 916,000 barrels per day in 2003, compared with 482,000 barrels per day in 2002. In addition, our Syncrude mining operations produced 19,000 barrels per day in 2003, compared with 8,000 barrels per day in 2002. Although the merger was the primary reason for the production increase, other items impacting our production rate in 2003 were:

- The startup of the Grane field in the Norwegian North Sea in September 2003;
- A full year's production from Phase I of the development of the Peng Lai 19-3 field in China's Bohai Bay; and
- The startup of production from the Phase I development of the Su Tu Den project in Vietnam late in the fourth quarter of 2003.

Included in international E&P's net income in 2003 was a net foreign currency transaction loss of $50 million, compared with a net loss of $34 million in 2002.

International E&P's net income in 2003 also was favorably impacted by the following items:

- In Norway, the Norway Removal Grant Act (1986) was repealed in the second quarter of 2003. Prior to its repeal, this Act required the Norwegian government to contribute to the cost of removing offshore oil and gas production facilities. Now, the co-venturers in the facilities must fund all removal costs, but can deduct the removal costs, as incurred, under the Petroleum Tax Act, at the marginal tax rate in effect at the time of removal. These changes required us: to recognize an additional liability for the government's share, prior to repeal of the Act, of the future removal costs, with a corresponding increase in properties, plants and equipment (PP&E); and to establish a net deferred tax asset for the temporary differences between the financial basis and tax basis of all of our Norwegian removal assets and liabilities. Some of the increases in PP&E were on shut-in fields, which led to immediate impairments of those properties. The overall impact on 2003 results was a net after-tax benefit of $87 million.
- In the Timor Sea region, ConocoPhillips and its co-venturers received final approvals from authorities to proceed with the natural gas development phase of the Bayu-Undan project in the second quarter of 2003. This approval allowed a broad ownership interest re-alignment among the co-venturers to proceed, which included our sale of a 10 percent interest in the project and the issuance of equity by previously wholly owned subsidiaries. In addition, the ratification of the Australia/Timor Lesté treaty lowered the company's deferred tax liability position. The net result of these events was an after-tax benefit of $51 million in 2003. See Note 7 — Subsidiary Equity Transactions, in the Notes to Consolidated Financial Statements, for additional information.
- In November 2003, the Canadian Parliament enacted federal tax rate reductions for oil and gas producers. As a result we recognized a $95 million benefit upon revaluation of our deferred tax liability in the fourth quarter.

2002 vs. 2001

Net income from international E&P operations increased 66 percent in 2002. The improvement reflects four months of increased production volumes following the merger. However, 2002 net income included a $24 million deferred tax charge related to tax law changes in the United Kingdom. Net income in 2002 also included a $77 million leasehold impairment of deepwater Block 34, offshore Angola, due to an unsuccessful exploratory well in the block, along with higher dry hole charges.

Our international crude oil production increased 64 percent in 2002, while natural gas production increased 126 percent. The increases were mainly due to the addition of four months of production from fields acquired in the merger.

Midstream

	2003	2002	2001
	Millions of Dollars		
Net Income*	**$ 130**	55	120
**Includes DEFS related net income:*	***$ 72***	*23*	*101*
	Dollars Per Barrel		
Average Sales Prices			
U.S. natural gas liquids*			
Consolidated	**$22.67**	19.07	—
Equity	**22.12**	15.92	18.77
	Thousands of Barrels Daily		
Operating Statistics			
Natural gas liquids extracted**	**219**	156	120
Natural gas liquids fractionated	**167**	133	108

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

2003 vs. 2002

The Midstream segment purchases raw natural gas from producers and gathers natural gas through extensive 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.

Our Midstream segment consists of a 30.3 percent interest in Duke Energy Field Services, LLC (DEFS), as well as our other natural gas gathering and processing operations, and natural gas liquids fractionation and marketing businesses, primarily in the United States, Canada and Trinidad.

Net income from the Midstream segment increased 136 percent in 2003, compared with 2002. The increase primarily was attributable to improved results from DEFS and the addition of midstream operations following the merger. DEFS' results mainly increased because of higher natural gas liquids prices in 2003. In addition, DEFS' results in 2002 included higher costs for gas imbalance adjustment accruals.

Included in the Midstream segment's 2003 net income was a basis-difference benefit of $36 million, compared with $35 million in 2002, representing the amortization of the excess amount of our 30.3 percent equity interest in the net assets of DEFS over the book value of our investment in DEFS.

2002 vs. 2001

Net income from the Midstream segment decreased 54 percent in 2002, compared with 2001. The decrease was primarily due to lower results from DEFS, which experienced a decline in natural gas liquids prices, increased costs for gas imbalance accruals and other adjustments, and higher operating expenses. These items were partially offset by the benefit of four months' results from operations acquired in the merger.

Included in the Midstream segment's net income in 2002 was a benefit of $35 million, representing the amortization of the basis difference between the book value of ConocoPhillips' contribution to DEFS and our 30.3 percent equity interest in DEFS. The corresponding amount for 2001 was $36 million.

R&M

	2003	2002	2001
	Millions of Dollars		
Net Income			
United States	**$ 990**	138	395
International	**282**	5	2
	$1,272	143	397
	Dollars Per Gallon		
U.S. Average Sales Prices*			
Automotive gasoline			
Wholesale	**$ 1.05**	.96	.83
Retail	**1.35**	1.03	1.01
Distillates — wholesale	**.92**	.77	.78

**Excludes excise taxes.*

	2003	2002	2001
	Thousands of Barrels Daily		
Operating Statistics			
Refining operations*			
United States			
Rated crude oil capacity**	**2,168**	1,829	732
Crude oil runs	**2,074**	1,661	686
Capacity utilization (percent)	**96%**	91	94
Refinery production	**2,301**	1,847	795
International			
Rated crude oil capacity**	**442**	195	22
Crude oil runs	**385**	152	20
Capacity utilization (percent)	**87%**	78	91
Refinery production	**412**	164	19
Worldwide			
Rated crude oil capacity**	**2,610**	2,024	754
Crude oil runs	**2,459**	1,813	706
Capacity utilization (percent)	**94%**	90	94
Refinery production	**2,713**	2,011	814
Petroleum products sales volumes			
United States			
Automotive gasoline	**1,369**	1,230	537
Distillates	**575**	502	225
Aviation fuels	**180**	185	78
Other products	**492**	372	220
	2,616	2,289	1,060
International	**430**	162	10
	3,046	2,451	1,070

**Includes our share of equity affiliates.*
***Weighted-average crude oil capacity for the period, including the refineries acquired in the Tosco acquisition in September 2001 and the refineries acquired as a result of the merger. Actual capacity at year-end 2002 and 2001 was 2,166,000 and 1,656,000 barrels per day, respectively, in the United States and 440,000 and 72,000 barrels per day, respectively, internationally.*

2003 vs. 2002

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

Net income from our R&M segment increased substantially in 2003, compared with 2002. The improved results primarily were due to significantly higher U.S. refining margins. The addition of refining and marketing assets in the merger also contributed to the higher 2003 earnings, as did increased wholesale gasoline margins. Partially offsetting the improvements was a net charge of $125 million for the cumulative effect of the adoption of FIN 46 for variable interest entities involving synthetic leases and certain other financing structures.

Our refineries produced 2.7 million barrels per day of petroleum products in 2003, compared with 2.0 million barrels per day in 2002. The increase reflects the addition of production from refineries acquired in the merger.

2002 vs. 2001
Net income from the R&M segment declined 64 percent in 2002, compared with 2001, reflecting lower refining margins, along with an $84 million after-tax impairment of a tradename and leasehold improvements of certain retail sites. R&M earnings for 2002 included four months' results from operations acquired in the merger, as well as the impact of a full year's results from Tosco operations, while the 2001 results included Tosco operations for only the last three and one-half months of 2001.

Worldwide crude oil refining capacity utilization was 90 percent in 2002, compared with 94 percent in 2001. Our refineries produced 2.0 million barrels per day of petroleum products in 2002, compared with 814,000 barrels per day in 2001. The increase reflects a full year of operations for refineries acquired in the Tosco acquisition and four months of operations for the refineries acquired in the merger.

U.S. R&M

2003 vs. 2002
Net income from our U.S. R&M operations increased significantly in 2003, compared with 2002. The improved results mainly were due to significantly higher refining margins, particularly during the third quarter of 2003. Industry U.S. refining margins were strong in the third quarter of 2003 due to increased gasoline demand in August and an unusual number of refined product supply disruptions, including refinery outages in the Midwest caused by a major power blackout in August 2003. See the "Outlook" section for additional discussion of refining margins. We capitalized on the strong refining margins in the third quarter by running our U.S. refineries at a utilization rate of 96 percent during the quarter. However, this rate was negatively impacted by a fire at our Ponca City, Oklahoma, refinery during July that resulted in portions of the facility being shut down. The Ponca City refinery's throughput was restored in the fourth quarter of 2003 to levels achieved before the fire.

The addition of refining and marketing assets in the merger also contributed to the higher 2003 earnings, as did increased wholesale gasoline margins. Partially offsetting the margin improvements in 2003 was a net charge of $125 million for the cumulative effect of the adoption of FIN 46 for variable interest entities involving synthetic leases and certain other financing structures, along with higher utility costs.

For the full year of 2003, our U.S. refineries ran at a crude oil capacity utilization rate of 96 percent, compared with 91 percent in 2002. The rate in 2002 was lowered by higher maintenance turnaround activity, the impact of tropical storms on our Gulf Coast refineries, and the loss of Venezuelan crude oil supply in the fourth quarter due to the economic and political instability in that country during the quarter.

2002 vs. 2001
Net income from U.S. R&M operations declined 65 percent in 2002, compared with 2001. The decrease was primarily due to lower refining margins, particularly in the Midcontinent and Gulf Coast regions, along with an $84 million after-tax impairment of a tradename and leasehold improvements of certain retail sites. These items were partially offset by increased production and sales volumes as a result of the Tosco acquisition and the merger. Net income for 2002 included four months of operations acquired in the merger, and a full year of Tosco operations, while the 2001 results included Tosco operations for only three and one-half months. Effective January 1, 2001, we changed our method of accounting for the costs of major maintenance turnarounds from the accrue-in-advance method to the expense-as-incurred method. The cumulative effect of this change in accounting principle increased R&M net income by $26 million. Also included in 2001 was a $27 million write-down of inventories to market value.

International R&M

2003 vs. 2002
Net income from our international R&M operations increased substantially in 2003, compared with 2002. The improvement was due to the larger size and scope of our international refining and marketing operations following the merger, along with higher international refining margins. Prior to the merger, our international R&M operations consisted only of our Whitegate refinery in Ireland with a rated crude oil capacity of 72,000 barrels per day. The merger added one wholly owned and four joint-venture refineries, with a rated crude oil capacity of 370,000 barrels per day. In addition, the merger added an extensive marketing network throughout Europe and Asia. Included in international R&M's net income in 2003 was a net foreign currency gain of $18 million, compared with a net gain of $9 million in 2002.

Our international crude oil capacity utilization rate was 87 percent in 2003, compared with 78 percent in 2002. The lower utilization rate in 2002 primarily was the result of the Humber refinery in the United Kingdom being shut down for an extended period of time in the fourth quarter due to a power outage and subsequent downtime.

2002 vs. 2001
Net income from international R&M operations increased $3 million in 2002, compared with 2001, reflecting the impact of the merger. The Humber refinery was shut down for an extended period of time during the fourth quarter of 2002, which negatively impacted international R&M's 2002 results.

Chemicals

	Millions of Dollars		
	2003	2002	2001
Net Income (Loss)	**$ 7**	(14)	(128)

2003 vs. 2002

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

As the results in both years indicate, the chemicals industry continues to be challenged to effectively utilize capacity, manage costs and improve margins in a difficult economic environment. The worldwide chemicals industry experienced an economic downturn beginning in the second half of 2000, and the downturn continued through 2003. The downturn has led to excess production capacity in the industry and pressured margins on key products. The chemicals industry has also been impacted by high energy prices, which negatively impacts both utility and feedstock costs.

2002 vs. 2001

The Chemicals segment incurred a net loss of $14 million in 2002, compared with a net loss of $128 million in 2001. Higher margins in 2002 contributed to the improvement in results. Lower operating expenses, feedstock costs and energy prices in 2002 were partially offset by decreased sales prices.

Due to depressed economic conditions in the chemicals industry, asset retirements and impairments totaling $84 million after-tax were recognized by CPChem in 2001. A developmental reactor at the Pasadena Plastics Complex in Pasadena, Texas, was retired; accelerated depreciation was recognized by CPChem on two polyethylene reactors at the Orange chemical plant in Orange, Texas; an ethylene unit was retired at the Sweeny complex in Old Ocean, Texas; an equity affiliate of CPChem recorded a property impairment related to a polypropylene facility; property impairments were taken on the manufacturing facility in Puerto Rico; and the benzene and cyclohexane units at the Puerto Rico facility were retired. In addition, the valuation allowance on the Puerto Rico facility's deferred tax asset related to its net operating losses was increased in 2001 so that the deferred tax assets were fully offset by valuation allowances. Partially offsetting these impairments and retirements was a business interruption insurance settlement recognized by CPChem, and a favorable deferred tax adjustment recorded by ConocoPhillips related to the Puerto Rico facility, together totaling $57 million after-tax.

Emerging Businesses

	Millions of Dollars		
	2003	2002	2001
Net Loss			
Technology solutions	**$ (20)**	(16)	(12)
Gas-to-liquids	**(50)**	(273)	—
Power	**(5)**	(3)	—
Other	**(24)**	(18)	—
	$ (99)	(310)	(12)

2003 vs. 2002

The Emerging Businesses segment includes the development of new businesses outside our traditional operations. Emerging Businesses incurred a net loss of $99 million in 2003, compared with a net loss of $310 million in 2002. The net loss in 2003 was less than that in 2002 as a result of a $246 million write-off of purchased in-process research and development costs in the third quarter of 2002 related to Conoco's natural gas-to-liquids and other technologies. In accordance with FASB Interpretation No. 4, "Applicability of FASB Statement No. 2 to Business Combinations Accounted for by the Purchase Method," value assigned to research and development activities in the purchase price allocation that have no alternative future use are required to be charged to expense at the date of the consummation of the combination. The $246 million charge was the same on both a before-tax and after-tax basis, because there was no tax basis in the assigned value prior to its write-off.

2002 vs. 2001

The Emerging Businesses segment posted a net loss of $310 million in 2002, compared with a net loss of $12 million in 2001. Results for 2002 included a $246 million write-off of acquired in-process research and development costs described above. The increased number of developing businesses after the merger also contributed to the larger losses in 2002.

Corporate and Other

	Millions of Dollars		
	2003	2002	2001
Net Loss			
Net interest	**$ (632)**	(412)	(262)
Corporate general and administrative expenses	**(173)**	(173)	(114)
Discontinued operations	**237**	(993)	32
Merger-related costs	**(223)**	(307)	—
Cumulative effect of accounting changes	**(112)***	—	—
Other	**26**	(33)	(71)
	$ (877)	(1,918)	(415)

**Includes a $107 million charge related to discontinued operations.*

2003 vs. 2002

Net interest after-tax represents interest expense, net of interest income and capitalized interest, as well as premiums incurred on the early retirement of debt. Net interest increased 53 percent in 2003, compared with 2002. The increase in 2003 mainly was due to our higher debt levels following the merger, the impact of the adoption of FIN 46 for variable interest entities involving synthetic leases and certain other financing structures, and increased premiums on the early retirement of debt. The adoption of FIN 46 at January 1, 2003, increased debt, which resulted in higher interest expense. See Note 2 — Changes in Accounting Principles, in the Notes to Consolidated Financial Statements, for additional information.

After-tax corporate general and administrative expenses were the same in 2003 as in 2002. Expenses in 2003 were impacted by the merger, as well as the expensing of stock options. Beginning in 2003, on a prospective basis, we elected to use the fair-value accounting method provided for under SFAS No. 123, "Accounting for Stock-Based Compensation." Offsetting these items were increased allocations of certain staff costs to the operating segments in 2003. The increased corporate allocations did not have a material impact on the operating segments' results.

Income from discontinued operations was $237 million in 2003, compared with a loss of $993 million in 2002. The net loss in 2002 reflects charges totaling $1,008 million after-tax related to the impairment of properties, plants and equipment; goodwill; intangible assets; and provisions for losses associated with various operating lease commitments. For additional information about our discontinued operations, see Note 4 — Discontinued Operations, in the Notes to Consolidated Financial Statements.

On an after-tax basis, merger-related costs were $223 million in 2003, compared with $307 million in 2002. Included in these costs were employee relocation expenses, transition labor costs, and other charges directly associated with the merger.

The category "Other" consists primarily of items not directly associated with the operating segments on a stand-alone basis, including certain foreign currency transaction gains and losses, and environmental costs associated with sites no longer in operation. Results from Other were improved in 2003 because of higher foreign currency transaction gains and an after-tax gain of $34 million in the first quarter of 2003, representing beneficial interests we had in certain insurance companies as a result of the conversion of those companies from mutual companies to stock companies, a process known as demutualization. These beneficial interests arose from our prior purchase and ownership of various insurance policies and contracts issued by the mutual companies. Prior to the demutualizations, our mutual ownership interests in these insurance companies were not recognized because the ownership interests in the mutual companies were neither capable of valuation nor marketable. Included in Other in 2003 was a net foreign currency transaction gain of $67 million, after-tax, compared with a net gain of $21 million in 2002.

2002 vs. 2001

Corporate and Other's net loss was $1,918 million in 2002, compared with $415 million in 2001. The increased net loss in 2002 reflects losses from discontinued operations, primarily due to impairments, and merger-related costs. Net interest expense and corporate general and administrative costs were also higher in 2002 due to the merger.

Capital Resources and Liquidity

Financial Indicators

	Millions of Dollars Except as Indicated		
	2003	2002	2001
Current ratio	**.8**	.9	1.3
Net cash provided by operating activities	**$ 9,356**	4,978	3,559
Total debt repayment obligations due within one year	**$ 1,440**	849	44
Total debt*	**$17,780**	19,766	8,654
Mandatorily redeemable preferred securities of trust subsidiaries*	**$ —**	350	650
Other minority interests	**$ 842**	651	5
Common stockholders' equity	**$34,366**	29,517	14,340
Percent of total debt to capital**	**34%**	39	37
Percent of floating-rate debt to total debt	**17%**	12	20

**With the adoption of Financial Accounting Standards Board Interpretation No. 46, "Consolidation of Variable Interest Entities," effective January 1, 2003, the mandatorily redeemable preferred securities were removed from our balance sheet and effectively replaced with debt.*

***Capital includes total debt, mandatorily redeemable preferred securities, other minority interests and common stockholders' equity.*

To meet our liquidity requirements, including funding our capital program, paying dividends and repaying debt, we look to a variety of funding sources, primarily cash generated from operating activities. During 2003, available cash was used to support the company's ongoing capital expenditures program, repay debt and pay dividends. In October 2003, our Board of Directors (Board) declared a dividend of $.43 per share, payable December 1, 2003, which represented a 7.5 percent increase from the previous quarter's dividend rate. Total dividends paid on our common stock in 2003 was $1.1 billion. During 2003, cash and cash equivalents increased $183 million to $490 million.

Significant Sources of Capital

Operating Activities

During 2003, cash of $9,356 million was provided by operating activities, an increase of $4,378 million from 2002. The increase in cash provided by operating activities was primarily due to:

- Higher crude oil, natural gas and natural gas liquids prices;
- Increased production as a result of the inclusion of Conoco activity for the full year; and
- Higher refining and marketing margins.

In addition, working capital changes increased cash flow from operating activities $589 million in 2003, compared with an increase of $982 million in 2002. Cash from operating activities provided by discontinued operations amounted to $189 million, compared with $202 million in 2002.

Asset Sales

Following the merger, we initiated an asset disposition program to sell approximately $3 billion to $4 billion of assets by the end of 2004. Through year-end 2003, we had sold approximately $3.4 billion of assets and raised our target to $4.5 billion by year-end 2004. In February 2004, we sold our 46.7 percent interest in Petrovera Resources Limited, which primarily produced conventional heavy oil in Western Canada. Additional assets expected to be sold in 2004 are primarily related to our marketing business. In addition, we are proceeding with plans to dispose of some of our non-DEFS Midstream assets. During 2003, $2.7 billion was received from the sale of various assets, including the remaining assets required to be sold by the Federal Trade Commission as a result of the merger, a substantial portion of our U.S. retail marketing sites, and non-strategic E&P properties. Proceeds from these asset sales have been, and will be, used primarily to pay off debt.

Commercial Paper and Credit Facilities

While the stability of our cash flows from operating activities benefits from geographic diversity and the effects of upstream and downstream integration, our operating cash flows remain exposed to the volatility of commodity crude oil and natural gas prices and refining and marketing margins, as well as periodic cash needs to finance tax payments and crude oil, natural gas and petroleum product purchases. Our primary funding source for short-term working capital needs is a $4 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. At December 31, 2003, we had $709 million of commercial paper outstanding, compared with $1,517 million of commercial paper outstanding at December 31, 2002, of which $206 million was denominated in foreign currencies.

Effective October 14, 2003, we entered into two new revolving credit facilities to replace our previously existing $2 billion 364-day facility that expired on that same date. The new revolving credit facilities consist of a $1.5 billion 364-day facility and a $500 million five-year facility. We also have two revolving credit facilities totaling $2 billion expiring in October 2006. There were no outstanding borrowings under these facilities at December 31, 2003. These credit facilities support the company's $4 billion commercial paper program. In addition, one of our Norwegian subsidiaries has two $300 million revolving credit facilities that expire in June 2004, under which no borrowings were outstanding at December 31, 2003.

Moody's Investor Service has maintained a rating of A3 on our senior long-term debt; and Standard and Poors' Rating Service and Fitch have maintained 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 $4.6 billion revolving credit facilities. Based on our year-end commercial paper balance of $709 million, we had access to $3.9 billion in borrowing capacity as of December 31, 2003, which provides ample liquidity to cover daily operations.

Shelf Registration

In late 2002, we filed a universal shelf registration statement with the U.S. Securities and Exchange Commission for various types of debt and equity securities. As a result, we have available to issue and sell a total of $5 billion of various types of securities under the universal shelf registration statement.

Minority Interests

At December 31, 2003, we had outstanding $842 million of equity held by minority interest owners, including a net minority interest of $496 million in Ashford Energy Capital S.A. and a $141 million net minority interest in Conoco Corporate Holdings L.P.

- In December 2001, in order to raise funds for general corporate purposes, Conoco and Cold Spring Finance S.a.r.l. formed Ashford Energy Capital S.A. through the contribution of a $1 billion Conoco 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 1.27 percent. The preferred return at December 31, 2003, was 2.48 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, Ashford would require a letter of credit to support $475 million of the term loans, as of December 31, 2003, 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, 2003, Ashford held $1.6 billion of ConocoPhillips subsidiary notes and $25 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.
- In 1999, in order to raise funds for general corporate purposes, Conoco formed Conoco Corporate Holdings L.P., contributing an office building and four aircraft to the partnership. Conoco Corporate Holdings L.P. is a limited-life entity that must be liquidated in 2019. The limited partner interest was sold to Highlander Investors L.L.C. for $141 million, which represented an initial net 47 percent interest. Highlander's current investment in Conoco Corporate Holdings L.P. is 24.4 percent. Highlander is entitled to a cumulative annual priority return on its investment of 7.86 percent. The net minority interest in Conoco Corporate Holdings L.P. was $141 million at December 31, 2003 and 2002, and is callable without penalty beginning in the fourth quarter of 2004.

Receivables Factoring
At December 31, 2003 and 2002, we also had sold $226 million and $264 million, respectively, of receivables under factoring arrangements. We retained servicing responsibility for these sold receivables, which gives us certain benefits, the fair value of which approximates the fair value of the liability incurred for continuing to service the receivables. See Note 15 — Sales of Receivables, in the Notes to Consolidated Financial Statements, for additional information.

Off-Balance Sheet Arrangements

Receivables Monetization
At December 31, 2002, certain credit card and trade receivables had been sold to two Qualifying Special Purpose Entities (QSPEs) in revolving-period securitization arrangements. These arrangements provided for us to sell, and the QSPEs to purchase, certain receivables and for the QSPEs to then issue beneficial interests of up to $1.5 billion to five bank-sponsored entities. All five bank-sponsored entities are multi-seller conduits with access to the commercial paper market and purchase interests in similar receivables from numerous other companies unrelated to us. We have no ownership interests, nor any variable interests, in any of the bank-sponsored entities. As a result, we do not consolidate any of these entities. Furthermore, we do not consolidate the QSPEs because they meet the requirements of SFAS No. 140, "Accounting for Transfers and Servicing of Financial Assets and Extinguishments of Liabilities," to be excluded from the consolidated financial statements of ConocoPhillips.

During 2003, we purchased from the bank-sponsored entities the senior interests of one of our two existing QSPEs and discontinued selling receivables to it. We have consolidated this QSPE since acquiring the senior interests. Also during 2003, the third-party beneficial interest holders approved amendments to the other QSPE to increase the amount of third-party beneficial interests that can be issued to $1.2 billion. These changes resulted in a net reduction of the maximum level of senior beneficial interests that can be issued to third-party beneficial interest holders from $1.5 billion to $1.2 billion. At December 31, 2003 and 2002, we had sold accounts receivable of $1.2 billion and $1.3 billion, respectively. The receivables transferred to the QSPE meets the isolation requirements and other requirements of SFAS No. 140 to be accounted for as sales. Accordingly, receivables transferred to the QSPEs were accounted for as sales.

We retain beneficial interests in this QSPE that are subordinate to the beneficial interests issued to the bank-sponsored entities. These retained interests, which are reported on the balance sheet in accounts and notes receivable — related parties, were $1.3 billion at both December 31, 2003 and 2002. We also retain servicing responsibility related to the sold receivables, which gives us certain benefits, the fair value of which approximates the fair value of the liability incurred for continuing to service the receivables. The carrying value of the subordinated beneficial interests approximates fair market value due to the short term of the underlying assets, which makes stress testing unnecessary.

Preferred Stock
During 1996 and 1997, we formed two statutory business trusts, Phillips 66 Capital I (Trust I) and Phillips 66 Capital II (Trust II), with ConocoPhillips owning all of the common securities of the trusts. The sole purpose of the trusts was to issue preferred securities to outside investors, investing the proceeds thereof in an equivalent amount of subordinated debt securities of ConocoPhillips. The two trusts were established to raise funds for general corporate purposes. On May 31, 2002, we redeemed all of the outstanding subordinated debt securities held by Trust I, which triggered the redemption of the $300 million of trust preferred securities of Trust I at par value, $25 per share. The redemption was funded by the issuance of commercial paper.

At December 31, 2003, Trust II had $350 million of mandatorily redeemable preferred securities outstanding, whose sole asset was $361 million of ConocoPhillips' subordinated debt securities, which bear interest at 8 percent. Distributions on the trust preferred securities are paid by the trust with funds from interest payments made by ConocoPhillips on the subordinated debt securities. We made interest payments in 2003 totaling $29 million. In addition, we have guaranteed the payment obligations of the trust on the trust preferred securities to the extent we have made interest payments on the subordinated debt securities. Prior to January 1, 2003, we consolidated Trust II and the mandatorily redeemable preferred securities were presented in the mezzanine section of the balance sheet. The subordinated debt securities and related income statement effects were eliminated in our consolidated financial statements. However, with the adoption of the provisions of FIN 46, effective January 1, 2003, we were required to deconsolidate Trust II, which had the effect of increasing debt by $361 million since the subordinated debt securities were no longer eliminated in consolidation, and removing the mandatorily redeemable preferred securities from our balance sheet. When we redeem the subordinated debt securities, Trust II is required to apply all the redemption proceeds to the immediate redemption of the preferred securities. See Note 2 — Changes in Accounting Principles and Note 19 — Preferred Stock and Other Minority Interests, in the Notes to Consolidated Financial Statements, for additional information.

Affiliated Companies
As part of our normal ongoing business operations and consistent with normal industry practice, we invest in, 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. At December 31, 2003, we were liable for certain contingent obligations under various contractual arrangements as described below.

- **Hamaca:** The Hamaca project involves the development of heavy-oil reserves from the Orinoco Oil Belt. We own a 40 percent interest in the Hamaca project, which is operated by Petrolera Ameriven on behalf of the owners. The other participants in Hamaca are Petroleos de Venezuela S.A. (PDVSA) and ChevronTexaco Corporation. Our interest is held through a jointly owned limited liability company, Hamaca Holding LLC, for which we use the equity method of accounting. Hamaca Holding LLC revenues for 2003 were approximately $284 million, expenses were approximately $143 million and cash provided by operating activities was approximately $143 million. We have a 57.1 percent non-controlling ownership interest in Hamaca Holding LLC. In the second quarter of 2001, we, along with our co-venturers in the Hamaca project, secured approximately $1.1 billion in a joint debt financing for our heavy-crude oil project in Venezuela. The Export-Import Bank of the United States provided a guarantee supporting a 17-year-term $628 million bank facility. The joint venture also arranged a $470 million 14-year-term commercial bank facility for the project. Total debt of $969 million was outstanding under these credit facilities at December 31, 2003. Of this amount, $388 million is recourse to ConocoPhillips. The proceeds of these joint financings are being used to primarily fund a heavy-oil upgrader. The remaining necessary funding will be provided by capital contributions from the co-venturers on a pro rata basis to the extent necessary to successfully complete construction. Once completion certification is achieved (required by October 1, 2005), the joint project financings will become non-recourse with respect to the co-venturers and the lenders under those facilities can then look only to the Hamaca project's cash flows for payment.

- **Merey Sweeny L.P. (MSLP):** MSLP is a limited partnership in which we and PDVSA each own an indirect 50 percent interest. During 1999, MSLP issued $350 million of 8.85 percent bonds due 2019 that we, along with PDVSA, are jointly-and-severally liable for under a construction completion guarantee. The bond proceeds were used to fund construction of a coker, vacuum unit and related facilities at our Sweeny, Texas, refinery, plus certain improvements to existing facilities at the same location. MSLP owns the coker and vacuum unit and, in the third quarter of 2000, began processing long residue produced from the Venezuelan Merey crude oil delivered under a supply agreement that we have with PDVSA. MSLP charges us a fee, which totaled approximately $145 million in 2003, to process the long residue through the vacuum unit and coker. This is the partnership's primary source of revenue. MSLP revenues for 2003 were approximately $162 million, expenses were approximately $140 million and cash provided by operating activities was approximately $31 million. If completion certification is not attained by June 18, 2004, the 8.85 percent bonds could be called and the bondholders would look to the two MSLP partners for repayment. MSLP is currently awaiting receipt of a permit for a new waste water pipeline and working to resolve issues in placing its insurance program, after which we expect to achieve completion certification in the second quarter of 2004. Upon completion certification, the 8.85 percent bonds become non-recourse to the two MSLP partners and the bondholders can then look only to MSLP cash flows for payment.

We purchased the improvements to existing facilities from MSLP for a price equal to the cost of construction, and MSLP provided seller financing. Terms of financing provide for 240 monthly payments of principal and interest commencing September 2000 with interest accruing at a 7 percent annual rate. The principal balance due on the seller financing was $131 million at December 31, 2003, and is included as long-term debt in our balance sheet. MSLP pays a monthly access fee to us, which totaled approximately $20 million in 2003, for the use of the improvements to the refinery. The access fee equals the monthly principal and interest paid by us to purchase the improvements from MSLP. To the extent the access fee is not paid by MSLP, we are not obligated to make payments for the improvements.

During the first quarter of 2002, MSLP issued $25 million of tax-exempt bonds due 2021. This issuance, combined with similar bonds MSLP issued in 1998, 2000, and 2001, bring the total outstanding to $100 million. As a result of the company's support as a primary obligor of a 50 percent share of these MSLP financings, $50 million of long-term debt is included in our balance sheet at December 31, 2003 and 2002, respectively.

- **Other:** At December 31, 2003, we had guarantees of approximately $340 million outstanding for our portion of other joint-venture debt obligations, which have terms of up to 22 years. Included in these outstanding guarantees was $158 million associated with the Polar Lights Company joint venture in Russia. Payment will be required if a joint venture defaults on its debt obligations.

Capital Requirements

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

Our balance sheet debt at December 31, 2003, was $17.8 billion. This reflects debt reductions of approximately $4.8 billion during 2003, including accounting changes that increased balance sheet debt approximately $2.8 billion as a result of the adoption of FIN 46. See Note 2 — Changes in Accounting Principles and Note 14 — Debt, in the Notes to Consolidated Financial Statements, for additional information.

During 2003, we reduced our commercial paper balance outstanding from $1.5 billion at December 31, 2002, to $709 million at December 31, 2003. In 2003, we paid off the following notes and debt facilities as they were called or matured and funded the payments with cash from operating activities and proceeds from asset dispositions:

- $250 million 8.49% Notes due 2023, at 104.245 percent;
- $150 million 8.25% Mortgage Bonds due May 15, 2003;
- $250 million 7.92% Notes due in 2023, at 103.96 percent;
- $250 million 7.20% Notes due 2023, at 103.60 percent;
- $100 million 6.65% Notes that matured on March 1, 2003;
- $180 million SRW Cogeneration Limited Partnership note;
- $500 million Floating Rate Notes due April 15, 2003;
- $90 million Tosco Trust 2000-E 8.78% Senior Secured Notes due 2010;
- $245 million Tosco Trust 2000-E 8.58% Senior Secured Notes due 2010;
- $199 million Arctic Funding, Limited Partnership 6.85% Senior Secured Note due 2011;
- $100 million of floating rate aviation equipment lease obligations having a final maturity in 2004;

- $489 million of fixed and floating rate ocean vessel lease obligations having final maturities from 2004 to 2005; and
- $1,130 million of floating rate marketing lease obligations having maturities from 2003 to 2006.

In October and November 2003, we executed certain interest rate swaps that had the effect of converting $1.5 billion of debt from fixed to floating rate. These swaps qualify for hedge accounting under SFAS 133, "Accounting for Derivative Instruments and Hedging Activities."

Also during 2003, we issued $79.5 million of tax-exempt bonds and assumed an additional amount of $20 million.

Contractual Obligations

The following table summarizes our aggregate contractual fixed and variable obligations as of December 31, 2003:

	Millions of Dollars				
		Payments Due by Period			
At December 31, 2003	Total	Up to 1 Year	1-3 Years	3-5 Years	After 5 Years
Debt obligations*	$17,720	1,434	3,110	1,202	11,974
Capital lease obligations	60	6	12	38	4
Total debt	17,780	1,440	3,122	1,240	11,978
Operating lease obligations	3,073	471	810	619	1,173
Purchase obligations**	58,231	19,972	4,869	3,915	29,475
Other long-term liabilities***					
Asset retirement obligations	2,685	61	242	364	2,018
Accrued environmental costs	1,119	140	304	138	537
Total	$82,888	22,084	9,347	6,276	45,181

*Total debt excluding capital lease obligations. Includes net unamortized premiums and discounts.

**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 $23.0 billion, of which $11.1 billion are primarily related to the supply of crude oil to our refineries and the optimization of the supply chain, $5.6 billion primarily related to the supply of unfractionated NGLs to fractionators, optimization of NGL assets, and for resale to customers, $4.4 billion primarily related to natural gas for resale to customers, $1.7 billion of futures, and $217 million related to the purchase side of exchange agreements; (2) $23.3 billion of purchase commitments for products, mostly natural gas and natural gas liquids, from CPChem over the remaining term of 97 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-owners in these properties. Does not include: (1) purchase commitments for jointly owned fields and facilities where we are not the operator; (2) our agreement to purchase up to 104,000 barrels per day of Petrozuata crude oil for a market-based formula price over the term of the Petrozuata joint venture (about 35 years) in the event that Petrozuata is unable to sell the production for higher prices; and (3) an agreement to purchase up to 165,000 barrels per day of Venezuelan Merey, or equivalent, crude oil for a market price over a remaining 16-year term if a variety of conditions are met.

***Does not include: (1) Taxes — the company's consolidated balance sheet reflects liabilities related to income, excise, property, production, payroll and environmental taxes. We anticipate the current liability of $2,676 million for accrued income and other taxes will be paid in the next year. We have other accrued tax liabilities whose resolution may not occur for several years, so it is not possible to determine the exact timing or amount of future payments. 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; (2) Pensions — for the 2004 through 2008 time period, we expect to contribute an average of $400 million per year to our qualified and non-qualified pension and postretirement medical plans in the United States and an average of $100 million per year to our non-U.S. plans, which are expected to be in excess of required minimums in many cases. Our required minimum funding in 2004 is expected to be $95 million in the United States and $75 million outside the United States; (3) Severance — we have expected severance payments of $109 million in 2004 and $3 million in 2005; and (4) Interest — we anticipate payments of $1,046 million in 2004, $2,012 million for the period 2005 through 2006, $1,708 million for the period 2007 through 2008, and $8,955 million for the remaining years to total $13,721 million.

Capital Spending

Capital Expenditures and Investments

	Millions of Dollars			
	2004 Budget	**2003**	2002	2001
E&P				
United States — Alaska	$ 656	**570**	706	965
United States — Lower 48	763	**848**	499	389
International	3,939	**3,090**	2,071	1,162
	5,358	**4,508**	3,276	2,516
Midstream	10	**10**	5	—
R&M				
United States	1,039	**860**	676	423
International	246	**319**	164	5
	1,285	**1,179**	840	428
Chemicals	—	**—**	60	6
Emerging Businesses	62	**284**	122	—
Corporate and Other*	167	**188**	85	66
	$ 6,882	**6,169**	4,388	3,016
United States	$ 2,639	**2,493**	2,043	1,849
International	4,243	**3,676**	2,345	1,167
	$ 6,882	**6,169**	4,388	3,016
Discontinued operations	$ —	**224**	97	69

Excludes discontinued operations.

Our capital spending for continuing operations for the three-year period ending December 31, 2003, totaled $13.6 billion. Spending was primarily focused on the growth of our E&P business, with 76 percent of total spending for continuing operations in this segment. The capital programs of DEFS, our gas gathering, processing and marketing joint-venture company, and CPChem, our chemicals joint-venture company, are intended to be self-funding, and are not reflected in the amounts above.

Including about $500 million in capitalized interest and $400 million that will be funded by minority interests in the Bayu-Undan gas export project, our Board has approved $6.9 billion for capital projects and investments for continuing operations in 2004, a 12 percent increase over our 2003 capital spending of $6.2 billion. We plan to direct 78 percent of our 2004 capital budget to E&P and 19 percent to R&M. The remaining budget will be allocated toward emerging businesses, mainly power generation; and general corporate purposes, with a majority related to global integration of systems. Thirty-eight percent of the budget is targeted for projects in the United States.

E&P

Capital spending for continuing operations for E&P during the three-year period ending December 31, 2003, totaled $10.3 billion. The expenditures over the three-year period supported several key exploration and development projects including:

- National Petroleum Reserve-Alaska (NPR-A) and satellite field prospects on Alaska's North Slope;
- Magnolia development in the deepwater Gulf of Mexico;
- Canadian conventional oil and gas projects, the Surmont oil sands project and expansion of the Syncrude project;

- The Hamaca heavy-oil project in Venezuela's Orinoco Oil Belt;
- The Jade, Clair, CMS3 and Britannia satellite developments in the United Kingdom;
- The Grane field and Ekofisk Area growth project in the Norwegian North Sea;
- The Kashagan field in the north Caspian Sea, offshore Kazakhstan;
- The Peng Lai 19-3 discovery in China's Bohai Bay and additional Bohai Bay appraisal and satellite field prospects;
- The Bayu-Undan gas recycle and gas development projects in the Timor Sea;
- Blocks 15-1 and 15-2 in Vietnam;
- The Belanak and Suban projects in Indonesia; and
- Acquisition of deepwater exploratory interests in Angola, Nigeria, Brazil, and the U.S. Gulf of Mexico.

Capital expenditures for construction of our Endeavour Class tankers and an additional interest in the Trans-Alaska Pipeline System were also included in the E&P segment.

We have contracted to build, for approximately $200 million each, five double-hulled Endeavour Class tankers for use in transporting Alaskan crude oil to the U.S. West Coast. During 2001, the *Polar Endeavour*, the first Endeavour Class tanker, entered service. The second tanker, the *Polar Resolution*, entered service in May 2002 and the third tanker, the *Polar Discovery*, was delivered for service in September 2003. We expect to add a new Endeavour Class tanker to our fleet in both 2004 and 2005, allowing us to retire older ships and cancel non-operated charters.

In Alaska, we continued development drilling in the Kuparuk, Tabasco and West Sak fields in the Greater Kuparuk Area, Prudhoe Bay satellite fields and the Alpine field. In 2003, we, along with our co-venturers, drilled or participated in 71 new development wells at Greater Prudhoe Bay, 17 new development wells at Greater Kuparuk and five development wells at Alpine. Also in 2003, funds were expended on the Alpine capacity expansion project that is expected to start up in the second half of 2004.

In the Lower 48, we continued to explore and develop our acreage positions in the deepwater Gulf of Mexico, South Texas, the San Juan Basin, the Permian Basin, and the Texas Panhandle. In the Gulf of Mexico, development drilling has been completed in the Magnolia and Princess Phase 1 fields. Sanction for the K2 project development is expected in the first quarter of 2004. Preliminary engineering for Princess Phase 2 and Ursa waterflood is expected to begin in the first quarter of 2004. Magnolia's tension-leg platform construction is ongoing and first production is expected prior to the end of 2004. In February 2003, we began drilling the Lorien exploration well on Block 199, which was declared a discovery in July. The well has been temporarily suspended pending evaluation of development alternatives. The Voss deepwater exploratory well drilled in Keathley Canyon Block 511 was declared dry in early 2003 and as required was charged against 2002 earnings. The Yorick deepwater exploratory well in Green Canyon Block 435 was declared a dry hole in late 2003.

Onshore capital was focused on natural gas developments in the San Juan Basin of New Mexico and the Lobo Trend of South Texas. In addition, Lower 48 is pursuing select opportunities in its other producing basins.

In Canada, we continued with development of the Stage III expansion-mining project in the Canadian province of Alberta, which is expected to increase our Canadian Syncrude production. The Aurora Train 2 project (the new mine) started up in late-October 2003. The upgrader expansion project is expected to start up in the second half of 2005. In the fourth quarter of 2003, approval was obtained for our project in Surmont. Our ownership share is 43.5 percent. The Surmont lease covers over 200 square miles. This initial development project is designed to use "steam assisted gravity drainage" technology, with first oil production expected in 2006. In addition to these projects, we also are involved in conventional oil and gas properties in Canada.

During the fourth quarter of 2001, we began production of heavy crude oil from the Hamaca project in Venezuela's Orinoco Oil Belt. Construction of an upgrader to convert heavy crude oil into a medium-grade crude oil continues. Completion of the upgrader is expected by the end of 2004. We own a 40 percent equity interest in the Hamaca project. Our other heavy-oil project in Venezuela, Petrozuata, incurred capital expenditures in 2003 associated with solids handling and restoration capacity projects, as well as ongoing drilling.

In addition to the Hamaca and Petrozuata developments, we have an interest in the Corocoro oil discovery in Venezuela's Gulf of Paria West. In April 2003, Venezuelan authorities and co-venturers approved Phase I of the development plan for the Corocoro field. We are the operator of the block. In September 2003, we acquired a 37.5 percent interest in the Gulf of Paria East Block. A portion of the Corocoro discovery extends onto this block. Our interest in the development is 32.2 percent.

In February 2003, Venezuelan authorities granted a 35-year license to ChevronTexaco to appraise and develop Plataforma Deltana Block 2. ChevronTexaco selected us as their minority partner in accordance with the terms of the license, which was approved by the Venezuelan government in late 2003. We now have a 40 percent interest in the project. Plataforma Deltana Block 2 is located to the east of our Corocoro discovery. Block 2 already has a gas discovery on it, and additional drilling is planned for 2004.

In Brazil, we added joint-venture partners for our two deepwater blocks, BM-ES-11 and BM-PAMA-3, and purchased additional seismic data in 2002. In 2003, 3-D seismic results indicated the prospect for BM-ES-11 was below expectations, leading to a write-off of our leasehold investment and the initiation of plans to exit the block. Further evaluation of BM-PAMA-3 is planned for 2004.

In 2003, we continued with several development projects in the U.K. and Norwegian sectors of the North Sea, including the Clair field in the U.K. sector. We expect first production from Clair in late 2004. Late in the third quarter of 2003, we and our co-venturers began oil production from the Grane field in the Norwegian North Sea. Net peak production from proved reserves of approximately 14,000 barrels per day is anticipated in 2005.

We continued the development of the CMS3 area, a single unitized project, comprising five natural gas reservoirs in the southern sector of the U.K. North Sea. Collectively, the fields are known as CMS3 due to their utilization of the production and transportation facilities of our operated Caister Murdoch System (CMS). In September 2002, production commenced from the Hawksley field, followed in the fourth quarter by production at the Murdoch K field. During 2003, McAdam came onstream in the second quarter and Watt began in the fourth quarter. Drilling operations on the final reservoir, Boulton H, are ongoing in 2004. We are the operator of CMS3 and hold a 59.5 percent interest.

In December 2003, our Board approved the development of the Britannia field satellites in the North Sea. A development plan has been submitted for government approval. These satellites are comprised of the Callanish and Brodgar fields. The Callanish field is an oil reservoir, and the Brodgar field is a gas condensate reservoir with properties similar to those of Britannia. The fields are planned to be developed jointly via a bridge-linked platform to Britannia, with production startup scheduled for 2007. We are the operator of both fields with an interest of 75 percent in Brodgar and 83.5 percent in Callanish.

Elsewhere in the Norwegian sector of the North Sea, in 2003, we, along with our co-venturers, approved a plan to further develop the Ekofisk Area to increase the recovery of oil and gas from the area by improving the area's processing capacity and reliability. The Ekofisk growth project consists of two interrelated components: the construction and installation of a new steel wellhead and process platform and an increase in capacity from existing facilities. We expect to complete and install the steel jacket in 2004 and the topsides early in the summer of 2005. Additional production from this development is anticipated to begin in the fall of 2005. We are modifying the existing Ekofisk Complex and four additional platforms to increase processing capacity.

In 2002, we and our co-venturers, in conjunction with the government of the Republic of Kazakhstan, declared the Kashagan field on the Kazakhstan shelf in the north Caspian Sea to be commercial. A development plan for the field was approved by the Republic of Kazakhstan in February 2004. Four of five planned appraisal wells on Kashagan had been successfully completed by the end of 2003. The fifth well is currently being tested. In May 2002, we along with the other remaining co-venturers, completed the acquisition of proportionate interests of two co-venturers' rights, which increased our ownership interest from 7.14 percent to 8.33 percent. In October 2002, we and our co-venturers announced a new hydrocarbon discovery in the Kazakhstan sector of the Caspian Sea. In 2003, a 3-D survey was carried out over the Kalamkas field and an initial appraisal well is planned for 2005.

During 2003, we exercised our pre-emptive rights related to B.G. International's sale of their share in the North Caspian License that includes the Kashagan field. The transaction is expected to close in 2004, at which time our interest in the license will increase from 8.33 percent to 10.19 percent. In November 2003, we and our co-venturers announced the successful completion of the first offshore exploration wells on the Aktote and Kashagan Southwest prospects. These two wells are located in the Kazakhstan sector of the Caspian Sea in an area adjacent to the Kashagan field. Another exploration well, on the Kairan prospect, completed drilling in 2003 and will be tested in 2004.

In late-December 2002, we began production from Phase I of our Peng Lai 19-3 development located on Block 11/05 in China's Bohai Bay. During 2003, we continued with planning and design for Phase II of the Peng Lai 19-3 development, which includes multiple wellhead platforms, central processing facilities, and a floating storage and offloading facility. We are developing, in conjunction with Phase II, the Peng Lai 25-6 oil field, located three miles east of Peng Lai 19-3. We also drilled exploration wells on the Peng Lai 19-9 prospect and the Peng Lai 13-1 prospect, which resulted in two discoveries. The Peng Lai 19-9-1 well is located two miles east of the Peng Lai 19-3 oil field, and along with adjacent structures will be a part of the Phase II development.

In the Timor Sea, we continued with development activities associated with the Bayu-Undan gas recycle and gas development projects. We continued to drill future production wells and have installed all major facilities, including two production, processing and living quarters platforms and an unmanned production platform. A multi-product floating, storage and offloading vessel was connected to the production facilities during the fourth quarter of 2003. First liquids production began in February 2004, and full capacity of 62,000 net barrels per day of condensate and natural gas liquids is anticipated to be reached in the third quarter of 2004. An average rate of 23,000 net barrels per day of combined condensate and natural gas liquids is expected for 2004.

We also have received approval of the gas development plan for the Bayu-Undan project from the Timor Sea Designated Authority, concluded fiscal and legal provisions with the government of Timor Lesté, and executed new production sharing contract (PSC) arrangements with the Designated Authority. The gas development project includes a liquefied natural gas (LNG) plant, including a pipeline to Darwin, Australia. The first LNG cargo from the 3.52 million-ton-per-year facility is scheduled for delivery in early 2006. During the third quarter of 2003, construction of the LNG facility and the pipeline began. In June 2003, we sold what currently equates to a 10.08 percent interest in the unitized Bayu-Undan field; purchased other interests that currently equate to a 2.65 percent interest in the field; sold a 43.3 percent interest in the Bayu-Undan pipeline under construction; and sold a 43.3 percent interest in Darwin LNG Pty Ltd (owner of the LNG plant to be constructed). The net result is that we retain a 56.72 percent controlling interest in the integrated project.

In Vietnam's Block 15-1, the Su Tu Den Phase I (southwest area) development project was approved in December 2001 and production from this area began in late-October 2003. We also are evaluating the commerciality of the Su Tu Vang fields and the northeast portion of the Su Tu Den field. In November 2003, we announced the completion of a successful exploratory well in the Su Tu Trang field in Block 15-1. Technical evaluation is in progress to assess the reservoir potential of the Su Tu Trang field.

In the third quarter of 2002, we began production from two new wellhead platforms in the Block 15-2 Rang Dong field in Vietnam. During late 2003, field facilities were upgraded to include a utilities-living quarters platform, and a central processing platform with facilities to enable gas lift, gas export and water injection. With the completion of these facilities, water injection is now possible on all three wellhead platforms and gas lift is possible on the N-1 and E-1 wellhead platforms. These facilities became operational in the fourth quarter of 2003.

We continued with the appraisal and development of key gas fields in Indonesia. In 2003, we announced the successful test of the Suban-8 delineation well on the southwest flank of the Suban gas field, located in the Corridor PSC of South Sumatra. We also completed the successful test of the North Sumpal-1 well in the Sakakemang Block located in South Sumatra, and continued on the construction of the South Jambi gas project in the South Jambi B Block also located in South Sumatra. In addition, we continue to develop the offshore Belanak and other fields in the Block B PSC in the Natuna Sea, for which a floating production storage and offloading vessel is under construction. The vessel is expected to be completed in the first half of 2005.

In May 2002, initial results showed that the first exploratory well drilled in Block 34, offshore Angola, was a dry hole. In view of this information, we reassessed the fair value of the remainder of the block and determined that our investment in the block was impaired by $77 million, both before- and after-tax. In December 2003, the second exploration well was drilled in Block 34, offshore Angola. The well encountered non-commercial gas and was plugged and abandoned. In view of this information, we fully impaired our remaining investment in the block.

In 2003, we obtained a 40 percent interest in Block 248 and a 20 percent interest in Block 214, both offshore Nigeria. First exploration drilling is planned for Block 248 in the second quarter of 2004.

Other capital spending for E&P during the three-year period ended December 31, 2003, supported:

- The Eldfisk waterflood development in Norway;
- The Jade field development in the United Kingdom;
- The acquisition and development of coalbed methane and conventional gas prospects and producing properties in the U.S. Lower 48; and
- North Sea prospects in the U.K. and Norwegian sectors, plus other Atlantic Margin wells in the United Kingdom, Greenland and the Faroe Islands.

2004 Capital Budget

E&P's 2004 capital budget for continuing operations is $5.4 billion, 19 percent higher than actual expenditures in 2003. Twenty-six percent of E&P's 2004 capital budget is planned for the United States, with 46 percent of that slated for Alaska.

We have budgeted $628 million for worldwide exploration capital activities in 2004, with 17 percent of that amount, $106 million, allocated to the United States. Outside the United States, significant exploration expenditures are planned in Kazakhstan, Venezuela, the United Kingdom and Norway.

We plan to spend $656 million in 2004 for our Alaskan operations. A majority of the capital spending will fund Prudhoe Bay, Greater Kuparuk and Western North Slope operations — including additional work on the Alpine capacity expansion project, Orion and West Sak field developments — construction of Endeavour Class tankers, and the exploratory activity discussed above.

In the Lower 48, offshore capital expenditures will be focused on the continued development of the Magnolia, Ursa and Princess fields in the deepwater Gulf of Mexico. Onshore capital will focus primarily on developing natural gas reserves within core areas, such as the San Juan Basin of New Mexico and the Lobo Trend of South Texas.

E&P is directing $3.9 billion of its 2004 capital budget to international projects. The majority of these funds will be directed to developing major long-term projects, including the Bayu-Undan liquids and gas development projects in the Timor Sea; the Hamaca heavy-oil project in Venezuela; additional development of oil and gas reserves in offshore Block B and onshore South Sumatra blocks in Indonesia; the second phase of Bohai Bay in China; projects in the Caspian region, including Baku-Tbilisi-Ceyhan pipeline; projects in Canada, including Syncrude, Surmont heavy-oil and the Mackenzie Delta gas development; and the Qatargas 3 LNG facility in Qatar. In addition, funds will be used to expand the company's positions in the U.K. and Norwegian sectors of the North Sea.

Costs incurred for the years ended December 31, 2003, 2002, and 2001, relating to the development of proved undeveloped oil and gas reserves were $2,002 million, $1,631 million, and $1,423 million, respectively. As of December 31, 2003, estimated future development costs relating to the development of proved undeveloped oil and gas reserves for the years 2004 through 2006 were projected to be $1,767 million, $1,111 million, and $659 million, respectively.

R&M

Capital spending for continuing operations for R&M during the three-year period ending December 31, 2003, was primarily for refinery-upgrade projects to improve product yields, to meet new environmental standards, to improve the operating integrity of key processing units, and to install advanced process control technology, as well as for safety projects. Total capital spending for continuing operations for R&M for the three-year period was $2.4 billion, representing 18 percent of our total capital spending for continuing operations.

Key projects during the three-year period included:

- Construction of a polypropylene plant at the Bayway refinery in New Jersey;
- Construction of a fluid catalytic cracking unit and a S Zorb™ Sulfur Removal Technology (S Zorb) unit at the Ferndale, Washington, refinery;
- Expansion of the alkylation unit at the Los Angeles refinery;

- Capacity expansion and debottlenecking projects at the Borger, Texas, refinery;
- Completion of a commercial S Zorb unit at the Borger refinery;
- An expansion of capacity in the Seaway crude-oil pipeline; and
- Installation of an advanced central control building and associated technologies at the Borger facility.

In early 2003, we completed three major projects: a polypropylene plant at the Bayway refinery in Linden, New Jersey, and both a fluid catalytic cracking unit and a S Zorb unit at the Ferndale, Washington, refinery. The Bayway polypropylene plant utilizes propylene feedstock from the Bayway refinery to make up to 775 million pounds per year of polypropylene. The plant became operational in March 2003. At Ferndale, the fluid catalytic cracking unit significantly improves gasoline production per barrel of crude input and the new S Zorb unit reduces sulfur in gasoline. Both became fully operational in 2003.

Also in 2003, we made investments related to clean fuels, safety and environmental projects throughout our refining system. We completed projects at our refineries in Ponca City, Oklahoma and Roxana, Illinois, to produce the low-sulfur gasoline required by the Environmental Protection Agency (EPA). We also began construction of a new diesel hydrotreater at the Rodeo facility of our San Francisco area refinery that is expected to produce reformulated California highway diesel an estimated one year ahead of the June 2006 deadline.

In July 2003, we completed the acquisition of certain refining assets in Hartford, Illinois, from Premcor. The operations of these assets are being integrated into the operations of our nearby Wood River refinery. The overall production of the refinery will only increase slightly, but integration of the new assets will enable the refinery to process heavier, lower cost crude oil. Startup of the integrated facilities is expected in the second quarter of 2004.

Internationally, we continue to invest in our ongoing refining and marketing operations, including a replacement reformer at our Humber refinery in the United Kingdom and marketing growth in select countries in Europe and Asia.

2004 Capital Budget

R&M's 2004 capital budget for continuing operations is $1.3 billion, a 9 percent increase over spending of $1.2 billion in 2003. Domestic spending is expected to consume 81 percent of the R&M budget.

We plan to direct about $900 million of the R&M capital budget to domestic refining, primarily to fund clean fuels projects in order to comply with new EPA standards for refined products. Worldwide, clean fuels spending for our R&M business is expected to be about $600 million, or 55 percent of the total refining budget. Our U.S. marketing and transportation businesses are expected to spend about $125 million, while the remaining budget will fund projects in our international refining and marketing businesses in Europe and the Asia Pacific region.

Emerging Businesses

Capital spending for Emerging Businesses during 2003 was primarily for construction of the Immingham combined heat and power cogeneration plant near the company's Humber refinery in the United Kingdom. We expect the plant to be operational in mid-2004.

Emerging Businesses' 2004 capital budget of $62 million is primarily dedicated to the completion of the Immingham plant.

Contingencies

Legal and Tax Matters

We accrue for contingencies when a loss is probable and the amounts can be reasonably estimated. Based on currently available information, we believe that it is remote that future costs related to known contingent liability exposures will exceed current accruals by an amount that would have a material adverse impact on the company's financial statements.

All significant litigation arising from the March 27, 2000, explosion and fire that occurred in an out-of-service butadiene storage tank at the K-Resin styrene-butadiene copolymer (SBC) plant has now been resolved.

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 industry; and refining, marketing and transportation of crude oil and refined products 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; and
- 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. Under the Clean Air Act, the EPA has promulgated a number of stringent limits on air emissions and established a federally mandated operating permit program. Violations of the Clean Air Act and most other environmental laws and regulations in the United States are enforceable with civil and criminal sanctions.

The EPA also has promulgated specific rules governing the sulfur content of gasoline, known generically as the "Tier II Sulfur Rules," the first phase requirements of which became applicable to our gasoline as of January 2004. To meet the requirements, we are implementing a compliance strategy that relies on the use of a combination of technologies, including our proprietary S Zorb technology.

The EPA also has promulgated rules regarding the sulfur content in highway diesel fuel, which become applicable in 2006. In April 2003, the EPA proposed a rule regarding emissions from non-road diesel engines and limiting non-road diesel fuel sulfur content. If promulgated, this rule would significantly reduce non-road diesel fuel sulfur content limits as early as 2007. We are currently evaluating S Zorb systems for removing sulfur from diesel fuel in special applications. The refining industry is actively considering several advanced and conventional technologies for complying with these rules. Because the non-road rule is not final, we are still evaluating and developing capital strategies for future compliance.

Additional areas of potential air-related impact are the proposed revisions to the National Ambient Air Quality Standards (NAAQS) and the Kyoto Protocol. In July 1997, the EPA promulgated more stringent revisions to the NAAQS for ozone and particulate matter. Since that time, final adoption of these revisions has been the subject of litigation (*American Trucking Association, Inc. et al. v. United States Environmental Protection Agency*) that eventually reached the U.S. Supreme Court during the fall of 2000. In February 2001, the U.S. Supreme Court remanded this matter, in part, to the EPA to address the implementation provisions relating to the revised ozone NAAQS. If adopted, the revised NAAQS could result in substantial future environmental expenditures for us.

In 1997, an international conference on global warming concluded an agreement, known as the Kyoto Protocol, which called for reductions of certain emissions that contribute to increases in atmospheric greenhouse gas concentrations. The United States has not ratified the treaty codifying the Kyoto Protocol but may in the future. In addition, other countries where we have interests, or may have interests in the future, have made commitments to the Kyoto Protocol and are in various stages of formulating applicable regulations. Currently, it is not possible to accurately estimate the costs that we could incur to comply with such regulations, but such expenditures could be substantial.

We also are subject to certain laws and regulations relating to environmental remediation obligations associated with current and past operations. Such laws and regulations include CERCLA and RCRA and their state equivalents. Remediation obligations include cleanup responsibility arising from petroleum releases from underground storage tanks located at numerous past and present ConocoPhillips-owned and/or operated petroleum-marketing outlets throughout the United States. Federal and state laws require that contamination caused by such underground storage tank releases be assessed and remediated to meet applicable standards. In addition to other cleanup standards, many states have adopted cleanup criteria for methyl tertiary-butyl ether (MTBE) for both soil and groundwater. MTBE standards continue to evolve, and future environmental expenditures associated with the remediation of MTBE-contaminated underground storage tank sites could be substantial.

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

We, from time to time, receive requests for information or notices of potential liability from the EPA and state environmental agencies alleging that we are a potentially responsible party under CERCLA or an equivalent state statute. On occasion, we also have been made a party to cost recovery litigation by those agencies or by private parties. These requests, notices and lawsuits assert potential liability for remediation costs at various sites that typically are not owned by us, but allegedly contain wastes attributable to our past operations. As of December 31, 2002, we reported we had been notified of potential liability under CERCLA and comparable state laws at

58 sites around the United States. In the 2002 report, sites from Phillips and Conoco were listed separately resulting in eight duplicate listings. These duplicate listings are consolidated in this 2003 report. At December 31, 2003, we had combined the eight duplicate listings, reclassified one existing site, and resolved six sites. Additionally, we had received 16 new notices of potential liability, leaving 61 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 $593 million in 2003 and are expected to be about $596 million in 2004 and $574 million in 2005. Capitalized environmental costs were $522 million in 2003 and are expected to be about $742 million and $967 million in 2004 and 2005, respectively.

Remediation Accruals

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 have 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, 2003.

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, 2003, our balance sheet included a total environmental accrual related to continuing operations of $1,119 million, compared with $743 million at December 31, 2002. The increase in accruals from year-end 2002, primarily resulted from evaluation of Conoco environmental liabilities during the purchase price allocation period. We expect to incur the 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 affect 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, alternative minimum tax credits, and loss carryforwards. Valuation allowances have been established for certain foreign and state net operating loss carryforwards that reduce deferred tax assets to an amount that will, more likely than not, be realized. Uncertainties that may affect the realization of these assets include tax law changes and the future level of product prices and costs. Based on our historical taxable income, our expectations for the future, and available tax-planning strategies, management expects that the net deferred tax assets will be realized as offsets to reversing deferred tax liabilities and as reductions in future taxable income. The alternative minimum tax credit can be carried forward indefinitely to reduce our regular tax liability.

New Accounting Developments

In December 2003, the FASB revised and reissued SFAS No. 132 (revised 2003), “Employers’ Disclosures about Pensions and Other Postretirement Benefits — an amendment of FASB Statements No. 87, 88, and 106,” which revises and requires additional disclosures about pension plans and other postretirement benefit plans. It does not change the measurement or recognition of those plans required by previous Financial Accounting Board Standards. We adopted the provisions of this Standard effective December 2003. Certain provisions of this Standard regarding disclosure of information about foreign plans and disclosure of estimated future benefit payments are not required until 2004. The adoption of the provisions applicable to 2003 did not have an impact on our results of operations or financial position, nor will the adoption of the additional provisions in 2004 have an impact on our results of operations or financial position.

In May 2003, the FASB issued SFAS No. 150, “Accounting for Certain Financial Instruments with Characteristics of

Liabilities and Equity," to address the balance sheet classification of certain financial instruments that have characteristics of both liabilities and equity. This statement was immediately effective for all contracts created or modified after May 31, 2003, and became effective July 1, 2003, for all previously existing contracts. On November 7, 2003, the FASB issued FASB Staff Position No. FAS 150-3, which deferred certain provisions of SFAS No. 150. As a result of adopting this new accounting standard in the third quarter of 2003, and the subsequent November 7, 2003, deferral of certain provisions, there was no impact on our 2003 financial statements. We continue to monitor the deferral status of SFAS No. 150.

In June 2001, the FASB issued SFAS No. 141, "Business Combinations," and SFAS No. 142, "Goodwill and Other Intangible Assets," which became effective on July 1, 2001, and January 1, 2002, respectively. The Securities and Exchange Commission (SEC) has requested the Emerging Issues Task Force (EITF) to consider the issue of whether SFAS Nos. 141 and 142 require interests held under oil, gas and mineral leases to be separately classified as intangible assets on the balance sheets of companies in the extractive industries. Historically, in accordance with SFAS No. 19, "Financial Accounting and Reporting by Oil and Gas Producing Companies," we have capitalized the cost of oil and gas leasehold interests and, consistent with industry practice, reported these assets as part of tangible E&P properties, plants and equipment.

If such interests were deemed to be intangible assets by the EITF, mineral rights to extract oil and gas for both proved and unproved properties would be classified separately from E&P properties, plants and equipment as intangible assets on our balance sheet. This interpretation by the EITF would only affect the classification of oil and gas mineral rights on our balance sheet and would not affect total assets, net worth, results of operations or cash flows.

E&P properties, plants and equipment at December 31, 2003 and 2002, included approximately $10.5 billion and $10.8 billion, respectively, of mineral rights to extract oil and gas, net of accumulated depletion, that would be reclassified on the balance sheet as intangible assets, if the interpretation that the SEC requested the EITF to consider was applied. We plan to continue to classify oil and gas mineral rights as E&P properties, plants and equipment until further guidance is provided by the EITF.

Critical Accounting Policies

The preparation of financial statements in conformity with generally accepted accounting principles requires management to select appropriate accounting policies and to make estimates and assumptions that affect the reported amounts of assets, liabilities, revenues and expenses. See Note 1 — Accounting Policies in the Notes to Consolidated Financial Statements for descriptions of our major accounting policies. Certain of these accounting policies involve judgments and uncertainties to such an extent that there is a reasonable likelihood that materially different amounts would have been reported under different conditions, or if different assumptions had been used. These critical accounting policies are discussed with the Audit and Compliance Committee on an annual basis and are presented below.

Oil and Gas Accounting

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

Property Acquisition Costs

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. By the end of the contractual period of the leasehold, the impairment probability percentage will have been adjusted to 100 percent if the leasehold is expected to be abandoned, or will have been adjusted to zero percent if there is an oil or gas discovery that is under development. See the supplemental Oil and Gas Operations disclosures about Costs Incurred and Capitalized Costs for more information about the amounts and geographic locations of costs incurred in acquisition activity, and the amounts on the balance sheet related to unproved properties.

Exploratory Costs

For exploratory wells, drilling costs are temporarily capitalized, or "suspended," on the balance sheet, pending a judgmental determination of whether potentially economic oil and gas reserves have been discovered by the drilling effort. This judgment usually is made within two months of the completion of the drilling effort, but can take longer, depending on the complexity of the geologic structure. Accounting rules require that this judgment be made at least within one year of well completion. If a judgment is made that the well did not encounter potentially economic oil and gas quantities, the well costs are expensed as a dry hole and are reported in exploration expense. Exploratory wells that are judged to have discovered potentially economic quantities of oil and gas and that are in areas where a major capital expenditure (e.g., a pipeline or offshore platform) would be required before production could begin, and where the economic viability of that major capital expenditure depends upon the successful completion of further exploratory work in the area, remain capitalized on the balance sheet as long as additional exploratory appraisal work is under way or firmly planned. For complicated offshore exploratory discoveries, it is not unusual to have exploratory wells remain suspended on the balance sheet for several years while we perform additional appraisal work on the potential oil and gas field. Unlike leasehold acquisition costs, there is no periodic impairment assessment of suspended exploratory well costs. Management continuously monitors the results of the additional appraisal drilling and seismic work and expenses the suspended well costs as dry holes when it judges that the potential field does not warrant further exploratory efforts in the near term. See the supplemental Oil and Gas Operations disclosures about Costs Incurred and Capitalized Costs for more information about the amounts and geographic locations of costs incurred in exploration activity and the amounts on the balance sheet related to unproved properties, as well as the Wells In Progress disclosure for the number and geographic location of wells not yet declared productive or dry.

Proved Oil and Gas Reserves

Engineering estimates of the quantities of recoverable oil and gas reserves in oil and gas fields are inherently imprecise and represent only approximate amounts because of the subjective judgments involved in developing such information. Despite the inherent imprecision in these engineering estimates, accounting rules require supplemental disclosure of "proved" oil and gas reserve estimates due to the importance of these estimates to better understanding the perceived value and future cash flows of a company's oil and gas operations. The judgmental estimation of proved oil and gas reserves also is important to the income statement because the proved oil and gas reserve estimate for a field serves as the denominator in the unit-of-production calculation of depreciation, depletion and amortization of the capitalized costs for that field. There are several authoritative guidelines regarding the engineering criteria that have to be met before estimated oil and gas reserves can be designated as "proved." Our reservoir engineering department has policies and procedures in place that are consistent with these authoritative guidelines. We have qualified and experienced internal engineering personnel who make these estimates. Proved reserve estimates are updated annually and take into account recent production and seismic information about each field. Also, as required by authoritative guidelines, the estimated future date when a field will be permanently shut-in for economic reasons is based on an extrapolation of oil and gas 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.

Canadian Syncrude Reserves

Canadian Syncrude proven reserves cannot be measured precisely. Reserve estimates of Canadian Syncrude are based on subjective judgments involving geological and engineering assessments of in-place crude bitumen volume, the mining plan, historical extraction recovery and upgrading 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 the bitumen and upgrading it into a light sweet crude oil. Despite the inherent imprecision in these engineering estimates, these estimates are used in determining depreciation expense.

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 12 — Property 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 production sites. The largest asset removal obligations facing us involve removal and disposal of offshore oil and gas platforms around the world, and oil and gas production facilities and pipelines in Alaska. The estimated discounted costs of dismantling and removing these facilities are accrued at the installation of the asset. Estimating the future asset removal costs necessary for this accounting calculation is difficult. Most of these removal obligations are many years in the future and the contracts and regulations often have vague descriptions of what removal practices and criteria will have to be met when the removal event actually occurs. Asset removal technologies and costs are constantly changing, as well as political, environmental, safety and public relations considerations. See Note 1 — Accounting Policies and Note 13 — Asset Retirement Obligations and Accrued Environmental Costs, 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 and, for major business acquisitions, typically engage an outside appraisal firm to assist in the fair value determination of the acquired long-lived assets. We have, if necessary, up to one year after the acquisition closing date to finish these fair value determinations and finalize the purchase price allocation.

Intangible Assets and Goodwill

In connection with the acquisition of Tosco Corporation on September 14, 2001, and the merger on August 30, 2002, we recorded material intangible assets for tradenames, air emission permit credits, and permits to operate refineries. These intangible assets were determined to have indefinite useful lives and so 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, which requires management's judgment of the estimated fair value of these intangible assets. See Note 6 — Acquisition of Tosco Corporation, Note 3 — Merger of Conoco and Phillips, and Note 12 — Property Impairments, in the Notes to Consolidated Financial Statements, for additional information.

Also in connection with the acquisition of Tosco and the merger, we recorded a material amount of goodwill. Under the accounting rules for goodwill, this intangible asset is not amortized. Instead, goodwill is subject to annual reviews for impairment based on a two-step accounting test. The first step is to compare the estimated fair value of any reporting units within the company that have recorded goodwill with the recorded net book value (including the goodwill) of the reporting unit. If the estimated fair value of the reporting unit is higher than the recorded net book value, no impairment is deemed to exist and no further testing is required that year. If, however, the estimated fair value of the reporting unit is below the recorded net book value, then a second step must be performed to determine the amount of the goodwill impairment to record, if any. In this second step, the estimated fair value from the first step is used as the purchase price in a hypothetical new acquisition of the reporting unit. The various purchase business combination rules are followed to determine a hypothetical purchase price allocation for the reporting unit's assets and liabilities. The residual amount of goodwill that results from this hypothetical purchase price allocation is compared with the recorded amount of goodwill for the reporting unit, and the recorded amount is written down to the hypothetical amount if lower. 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. A component is a reporting unit if the component constitutes a business for which discrete financial information is available and segment management regularly reviews the operating results of that component. However, two or more components of an operating segment shall be aggregated and deemed a single reporting unit if the components have similar economic characteristics. We have determined that we have three reporting units for purposes of assigning goodwill and testing for impairment. These are Worldwide Exploration and Production, Worldwide Refining and Worldwide Marketing. Our Midstream, Chemicals and Emerging Businesses operating segments were not assigned any goodwill from the merger because the two predecessor companies' operations did not overlap in these operating segments so we were unable to capture significant synergies and strategic advantages from the merger in these areas.

In our Exploration and Production operating segment, management reporting is primarily organized based on geographic areas. All of these geographic areas have similar business processes, distribution networks and customers, and are supported by a worldwide exploration team and shared services organizations. Therefore, all components have been aggregated into one reporting unit, Worldwide Exploration and Production, which is the same as the operating segment. In contrast, in our Refining and Marketing operating segment, management reporting is primarily organized based on functional areas. Because the two broad functional areas of Refining and Marketing have dissimilar business processes and customers, we concluded that it would not be appropriate to aggregate these components into only one reporting unit at the Refining and Marketing operating segment level. Instead, we have identified two reporting units within the operating segment: Worldwide Refining and Worldwide Marketing. Components in those two reporting units have similar business processes, distribution networks and customers. If we later reorganize our businesses or management structure so that the components within these three reporting units are no longer economically similar, the reporting units would be revised and goodwill would be re-assigned using a relative fair value approach in accordance with SFAS No. 142, "Goodwill and Other Intangible Assets." Goodwill impairment testing at a lower reporting unit level could result in the recognition of impairment that would not otherwise be recognized at the current higher level of aggregation. In addition, the sale or disposition of a portion of these three reporting units will be allocated a portion of the reporting unit's goodwill, based on relative fair values, which will adjust the amount of gain or loss on the sale or disposition.

Because quoted market prices for our reporting units are not available, management has to apply judgment in determining the estimated fair value of these reporting units for purposes of performing the first step of the periodic goodwill impairment test. Management uses all available information to make these fair value determinations, including the present values of expected future cash flows using discount rates commensurate with the risks involved in the assets and observed market multiples of operating cash flows and net income, and may engage an outside appraisal firm for assistance. In addition, if the first test step is not met, further judgment has to be applied in determining the fair values of individual assets and liabilities for purposes of the hypothetical purchase price allocation. Again, management has to use all available information to make these fair value determinations and may engage an outside appraisal firm for assistance. At year-end 2003, the estimated fair values of our Worldwide Exploration and Production, Worldwide Refining, and Worldwide Marketing reporting units, excluding those included in discontinued operations, ranged from between 15 percent to 35 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 impairment of the $15.1 billion of goodwill.

Inventory Valuation

Prior to the acquisition of Tosco in September 2001 and the merger in August 2002, our inventories on the last-in, first-out (LIFO) cost basis were predominantly reflected on the balance sheet at historical cost layers established many years ago, when price levels were much lower. Therefore, prior to 2001, our LIFO inventories were relatively insensitive to current price level changes. However, the acquisition of Tosco and the ConocoPhillips merger added LIFO cost layers that were recorded at replacement cost levels prevalent in late September 2001 and August 2002, respectively. As a result, our LIFO cost inventories are now much more sensitive to lower-of-cost-or-market impairment write-downs, whenever price levels fall. We recorded a LIFO inventory lower-of-cost-or-market impairment in the fourth quarter of 2001 due to a crude oil price deterioration. While crude oil is not the only product in the company's LIFO pools, its market value is a major factor in lower-of-cost-or-market calculations. We estimate that additional impairments could occur if a 60 percent/40 percent blended average of West Texas Intermediate/Brent crude oil prices falls below $21.25 per barrel at a reporting date. The determination of replacement cost values for the lower-of-cost-or-market test uses objective evidence, but does involve judgment in determining the most appropriate objective evidence to use in the calculations.

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 $85 million, while a 1 percent decrease in the return on plan assets assumption would increase annual benefit expense by $25 million.

Outlook

After adjusting for asset dispositions, E&P's worldwide production for 2004 is expected to be about the same level as it was in 2003. The dispositions contributed approximately 37,000 barrels of oil equivalent per day to 2003 production. For 2004, production increases in Asia Pacific and Latin America are expected to offset net declines in the United States, Canada and the North Sea.

In R&M, the optimization of spending related to clean fuels project initiatives will be an important focus area during 2004. In addition, we expect our average refinery crude oil utilization rate for 2004 to average about the same as in 2003.

Crude oil and natural gas prices are subject to external factors over which we have no control, such as global economic conditions, political events, demand growth, inventory levels, weather, competing fuels prices, and availability of supply. Crude oil prices rose significantly in 2003 due to supply disruptions during the year in several producing countries and the delays in the return of Iraqi crude production to the market in the face of rising global oil demand. As a result of these factors, global oil inventories remained at exceptionally low levels throughout 2003. Low oil inventories, coupled with economic recovery and the prospects for higher oil demand growth are expected to keep prices elevated through the first half of 2004. U.S. natural gas prices weakened moderately during the second half of 2003 from the very strong levels experienced during the second quarter, but the annual average was significantly higher in 2003 versus 2002. Prices weakened in the second half due to a strong buildup of natural gas inventories during the summer and early fall, as mild weather, weak industrial demand and fuel switching reduced natural gas demand. At the same time, high prices and the startup of a mothballed regasification terminal increased LNG imports to the United States. However, natural gas prices rose moderately in December, reflecting continuing concerns about the adequacy of gas supplies in the United States. Supply adequacy concerns are expected to keep prices above historical levels in 2004.

Refining margins are subject to movements in the price of crude oil and other feedstocks, and the prices of petroleum products, which are subject to market factors over which we have no control, such as the U.S. and global economies; government regulations; military, political and social conditions in oil producing countries; seasonal factors that affect demand, such as the summer driving months; and the levels of refining output and product inventories. U.S. and international refining and marketing margins rose in 2003 versus 2002, due to improved refined product demand and a series of supply disruptions. U.S. refining margins were above the five-year historical average in 2003 as a result of refinery outages in several regions of the United States, a product pipeline rupture in Arizona, and labor strikes in Venezuela, which removed both crude and refined products from the market. Combined with strong product demand, product inventories were drawn down to extremely low levels in the first half of the year, which elevated refining margins. Stronger demand in the face of tight supplies also improved marketing margins in 2003 versus 2002. The sustainability of current refining and marketing margins depends on the continued recovery of the global economy and refined product demand growth.

In February 2003, the Venezuelan government implemented a currency exchange control regime. The government has published legal instruments supporting the controls, one of which establishes official exchange rates for the U.S. dollar. The devaluation of the Venezuelan currency by approximately 17 percent in February 2004 did not have a significant impact on our Venezuelan operations; however, future changes in the exchange rate could have a significant impact on our Venezuelan operations. In addition, our Venezuelan operations remain subject to civil unrest in the country. Our Venezuelan operations contributed approximately $150 million to our 2003 net income.

In June 2003, we and our co-venturers in the Mackenzie gas project in Canada announced that funding and participation agreements have been reached and a preliminary information package was submitted to relevant regulatory authorities. The Mackenzie gas project involves natural gas production facilities, compression and gathering pipelines in the Mackenzie Delta area, and a pipeline system in the Mackenzie River Valley. The filing of the information package is a key step in the process leading to the submission of applications for the development of the natural gas fields and pipeline facilities. Regulatory applications are expected to be filed in 2004. First gas production is currently targeted to commence in late 2009.

In July 2003, we signed a Heads of Agreement with Qatar Petroleum for the development of Qatargas 3, a large-scale LNG project located in Qatar and servicing the U.S. natural gas market. This provides the framework for the necessary agreements and the completion of key feasibility studies. Qatargas 3 would be an integrated project, jointly owned by us and Qatar Petroleum, consisting of facilities to produce and liquefy gas from Qatar's North field. The LNG would be shipped from Qatar, and we would be responsible for regasification and marketing within the United States. Average daily gas sales volumes are projected to be approximately 1 billion cubic feet per day with startup anticipated in the 2009 timeframe.

In late October 2003, we signed a Heads of Agreement with the Nigerian National Petroleum Corporation, ENI and ChevronTexaco to conduct front-end engineering and design work for an LNG facility to be constructed in Nigeria's central Niger Delta. The participants have agreed to form an incorporated joint venture, Brass LNG Limited, to undertake the project. The engineering and design studies are expected to be completed in 2005, and the facility is targeted to be operational in 2009.

In December 2003, we signed a Statement of Intent with Qatar Petroleum regarding the construction of a gas-to-liquids plant in Ras Laffan, Qatar. The Statement of Intent initiates detailed technical and commercial pre-front-end engineering and design studies and establishes principles for negotiating a Heads of Agreement for an integrated reservoir-to-market plant. More definite agreements are expected in 2004.

Also in December 2003, we announced the signing of an agreement with Freeport LNG Development, L.P. to participate in its proposed LNG receiving terminal in Quintana, Texas. We would acquire 1 billion cubic feet per day of regasification capacity in the terminal for our use and obtain a 50 percent interest in the general partnership managing the venture. The terminal will be designed with a storage capacity of 6.9 billion cubic feet and a send-out capacity of 1.5 billion cubic feet per day. Pending government approvals, construction is scheduled to begin in the second half of 2004, with commercial startup in mid-2007.

In addition, we and our co-venturer are pursuing a proposed LNG receiving terminal in Harpswell, Maine. The proposal calls for construction of the terminal at a site previously used as a U.S. Navy fuel depot. LNG would be converted back to natural gas at the terminal for delivery through a new pipeline that would connect the terminal to the existing pipeline grid. Depending on receipt of the necessary regulatory approvals, construction could begin in 2006, with the facility operational by 2009.

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

This annual 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. Forward-looking statements can be identified by the words "expects," "anticipates," "intends," "plans," "projects," "believes," "estimates" and similar expressions.

We have 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 that these statements are not guarantees of future performance and involve risks, uncertainties and assumptions that we cannot predict. In addition, we have based many of these forward-looking statements on assumptions about future events that may prove to be inaccurate. Accordingly, our actual outcome 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;
- Changes in our business, operations, results and prospects;
- The operation and financing of our midstream and chemicals joint ventures;
- Potential failure to realize fully or within the expected time frame the expected cost savings and synergies from the combination of Conoco and Phillips;
- Costs or difficulties related to the integration of the businesses of Conoco and Phillips, as well as the continued integration of businesses recently acquired by each of them;
- 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;
- Failure of new products and services to achieve market acceptance;
- Unexpected cost increases or technical difficulties in constructing or modifying facilities for exploration and production projects, manufacturing or refining;

- Unexpected difficulties in manufacturing or refining our refined products, including synthetic crude oil, and chemicals products;
- Lack of, or disruptions in, adequate and reliable transportation for our crude oil, natural gas, 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;
- Potential disruption or interruption of our facilities due to accidents, political events or terrorism;
- International monetary conditions and exchange controls;
- Liability for remedial actions, including removal and reclamation obligations, under environmental regulations;
- Liability resulting from litigation;
- General domestic and international economic and political conditions, including armed hostilities, homeland security, and governmental disputes over territorial boundaries;
- Changes in tax and other laws or regulations applicable to our business; and
- Inability to obtain economical financing for exploration and development projects, construction or modification of facilities and general corporate purposes.

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 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 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 Executive Vice President of Commercial monitors commodity price risk. Both report to the Chief Executive Officer. The Commercial group 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 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 group 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; and
- 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 12 months ended December 31, 2003 and 2002, the gains or losses from this activity were not material to our cash flows or income from continuing operations.

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, 2003, as derivative instruments in accordance with SFAS No. 133, "Accounting for Derivative Instruments and Hedging Activities," as amended. 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, 2003 and 2002, was immaterial to our net income and cash flows. The VaR for instruments held for purposes other than trading at December 31, 2003 and 2002, 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 interest rates. The debt tables present principal cash flows and related weighted-average interest rates by expected maturity dates; the derivative table shows the notional quantities on which the cash flows will be calculated by swap termination date. 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				Mandatorily Redeemable Other Minority Interests and Preferred Securities	
Expected Maturity Date	Fixed Rate Maturity	Average Interest Rate	Floating Rate Maturity	Average Interest Rate	Fixed Rate Maturity	Average Interest Rate
Year-End 2003						
2004	**$ 1,360**	**5.91%**	**$ 7**	**5.85%**	**$ —**	**—%**
2005	**1,168**	**8.49**	**8**	**5.85**	**—**	**—**
2006	**1,506**	**5.82**	**320**	**2.71**	**—**	**—**
2007	**612**	**4.88**	**—**	**—**	**—**	**—**
2008	**18**	**7.10**	**500**	**1.05**	**—**	**—**
Remaining years	**10,849**	**6.98**	**776**	**1.59**	**141**	**7.86**
Total	**$15,513**		**$1,611**		**$ 141**	
Fair value	**$17,294**		**$1,611**		**$ 142**	
Year-End 2002						
2003	$ 762	7.99%	$ 706	2.60%	$ —	—%
2004	1,362	5.91	—	—	—	—
2005	1,169	8.49	—	—	—	—
2006	1,507	5.82	1,517	4.54	—	—
2007	613	4.88	—	—	—	—
Remaining years	10,740	6.95	691	6.02	491	7.96
Total	$16,153		$2,914		$ 491	
Fair value	$17,930		$2,914		$ 516	

In October and early November 2003, we executed certain interest rate swaps that had the effect of converting $1.5 billion of debt from fixed to floating rate. Under SFAS 133, "Accounting for Derivative Instruments and Hedging Activities," these swaps were designated as hedging the exposure to changes in the fair value of $400 million of 3.625% Notes due 2007, $750 million of 6.35% Notes due 2009, and $350 million of 4.75% Notes due 2012. These swaps qualify for the shortcut method of hedge accounting, so over the term of the swaps we will not recognize gain or loss due to ineffectiveness in the hedge.

	Interest Rate Derivatives		
Expected Maturity Date	Notional	Average Pay Rate	Average Receive Rate
Year-End 2003			
2004	**$ —**	**—%**	**—%**
2005	**—**	**—**	**—**
2006 — variable to fixed	**131**	**5.85**	**1.15**
2007 — fixed to variable	**400**	**1.07**	**3.63**
2008	**—**	**—**	**—**
Remaining years — fixed to variable	**1,100**	**2.67**	**5.84**
Total	**$1,631**		
Fair value position	**$ —**		
Year-End 2002			
2003 — variable to fixed	$ 500	3.41%	2.56%
2004	—	—	—
2005	—	—	—
2006 — variable to fixed	166	5.85	4.76
2007	—	—	—
Remaining years	—	—	—
Total	$ 666		
Fair value loss position	$ 22		

Foreign Currency Risk

We have foreign currency exchange rate risk resulting from operations in over 40 countries around the world. 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, 2003, 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 impact to income from an adverse hypothetical 10 percent change in the December 31, 2003, exchange rates.

The notional and fair market values of these positions at December 31, 2003, were as follows:

	Millions of Dollars	
Foreign Currency Swaps	Notional	Fair Market Value
Sell U.S. dollar, buy euro	$267	2
Sell U.S. dollar, buy British pound	789	26
Sell U.S. dollar, buy Danish krone	12	—
Sell U.S. dollar, buy Norway kroner	380	7
Sell U.S. dollar, buy Swedish krona	93	5

At December 31, 2002, ConocoPhillips had the following significant foreign currency derivative contracts:

- Approximately $194 million in foreign currency swaps hedging the company's European commercial paper program, with a fair value of $7.1 million;
- Approximately $536 million in foreign currency swaps hedging short-term intercompany loans between U.K. subsidiaries and a U.S. subsidiary, with a fair value of $9 million; and
- Approximately $24 million in foreign currency swaps hedging the company's firm purchase and sales commitments for gasoline in Germany, with a negative fair value of $4 million.

Although these swaps hedge exposures to fluctuations in exchange rates, the company 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. Assuming an adverse hypothetical 10 percent change in the December 31, 2002, exchange rates, the potential foreign currency remeasurement loss in non-cash pretax earnings from these swaps, intercompany loans, and commercial paper would be approximately $3 million.

In addition to the intercompany loans discussed above, at December 31, 2002, U.S. subsidiaries held long-term sterling-denominated intercompany receivables totaling $152 million due from a U.K. subsidiary. A Norwegian subsidiary held $198 million of intercompany U.S. dollar-denominated receivables due from its U.S. parent at December 31, 2002. The potential foreign currency remeasurement gains or losses in non-cash pretax earnings from a hypothetical 10 percent change in the year-end 2002 exchange rates from these intercompany balances was $35 million.

For additional information about our use of derivative instruments, see Note 18 — Derivative Instruments in the Notes to Consolidated Financial Statements.

Selected Financial Data

	Millions of Dollars Except Per Share Amounts				
	2003	2002*	2001*	2000	1999
Sales and other operating revenues	**$104,196**	56,748	24,892	22,155	14,988
Income from continuing operations	**4,593**	698	1,601	1,848	604
Per common share					
Basic	**6.75**	1.45	5.46	7.26	2.39
Diluted	**6.70**	1.44	5.43	7.21	2.37
Net income (loss)	**4,735**	(295)	1,661	1,862	609
Per common share					
Basic	**6.96**	(.61)	5.67	7.32	2.41
Diluted	**6.91**	(.61)	5.63	7.26	2.39
Total assets	**82,455**	76,836	35,217	20,509	15,201
Long-term debt	**16,340**	18,917	8,610	6,622	4,271
Mandatorily redeemable other minority interests and preferred securities	**141**	491	650	650	650
Cash dividends declared per common share	**1.63**	1.48	1.40	1.36	1.36

**Income from continuing operations, including related per share amounts, have been restated to reflect the adoption of Statement of Financial Accounting Standards No. 145, "Rescission of FASB Statements No. 4, 44, and 64, Amendment of FASB Statement No. 13, and Technical Corrections," as it relates to the classification of premiums paid on the early retirement of debt.*

See Management's Discussion and Analysis of Financial Condition and Results of Operations for a discussion of factors that will enhance an understanding of this data. The following transactions affect the comparability of the amounts included in the table above:

- The merger of Conoco and Phillips in 2002;
- The classification of a substantial portion of our retail marketing operations as discontinued operations in late 2002;
- The acquisition of Tosco Corporation in 2001;
- The acquisition of Atlantic Richfield Company's Alaskan operations in 2000; and
- The contribution of a significant portion of the company's midstream and chemicals businesses into joint ventures accounted for using equity-method accounting in 2000.

Also, see Note 2 — Changes in Accounting Principles, in the Notes to Consolidated Financial Statements, for information on changes in accounting principles that affect the comparability of the amounts included in the table above.

Selected Quarterly Financial Data

	Millions of Dollars				Per Share of Common Stock			
					Income (Loss) Before Cumulative Effect of Changes in Accounting Principles		Net Income (Loss)	
	Sales and Other Operating Revenues*	Income from Continuing Operations Before Income Taxes	Income (Loss) Before Cumulative Effect of Changes in Accounting Principles	Net Income (Loss)	Basic	Diluted	Basic	Diluted
2003								
First**	**$26,940**	**2,569**	**1,316**	**1,221**	**1.94**	**1.93**	**1.80**	**1.79**
Second**	**25,321**	**1,781**	**1,187**	**1,187**	**1.75**	**1.73**	**1.75**	**1.73**
Third	**26,105**	**2,310**	**1,306**	**1,306**	**1.92**	**1.90**	**1.92**	**1.90**
Fourth	**25,830**	**1,677**	**1,021**	**1,021**	**1.50**	**1.48**	**1.50**	**1.48**
2002								
First	$ 8,431	51	(102)	(102)	(.27)	(.27)	(.27)	(.27)
Second	10,414	657	351	351	.91	.91	.91	.91
Third	14,557	312	(116)	(116)	(.24)	(.24)	(.24)	(.24)
Fourth	23,346	1,121	(428)	(428)	(.63)	(.63)	(.63)	(.63)

**Includes excise taxes on petroleum products sales.*
***During the fourth quarter, in connection with the consolidation requirements of FASB Interpretation No. 46 for certain variable interest entities created before February 1, 2003, we made an additional adjustment of $18 million, or 3 cents per share, both on a basic and diluted basis, to Cumulative Effect of Changes in Accounting Principles. This adjustment was effective as of January 1, 2003, and as a result, the first and second quarter results have been restated from those disclosed in Note 2 — Changes in Accounting Principles, in the Notes to Consolidated Financial Statements, in our third quarter 2003 Form 10-Q.*

Quarterly Common Stock Prices and Cash Dividends Per Share

Phillips Petroleum Company's (predecessor to ConocoPhillips) stock was traded primarily on the New York, Pacific and Toronto stock exchanges. On August 30, 2002, it ceased trading.

Phillips Petroleum Company (predecessor to ConocoPhillips)	Stock Price		
	High	Low	Dividends
2002			
First	$63.80	55.30	.36
Second	64.10	54.53	.36
Third (through August 30)	59.21	44.75	N/A

ConocoPhillips' common stock began trading on September 3, 2002, the first trading day after the effective date of the merger. ConocoPhillips' common stock is traded on the New York Stock Exchange, under the symbol "COP".

	Stock Price		
	High	Low	Dividends
2003			
First	**$53.85**	**45.14**	**.40**
Second	**55.95**	**49.67**	**.40**
Third	**57.53**	**51.29**	**.40**
Fourth	**66.04**	**54.29**	**.43**
2002			
Third (from September 3)	$53.20	45.87	.36
Fourth	50.75	44.03	.40
Closing Stock Price at December 31, 2003			$65.57
Closing Stock Price at January 31, 2004			$65.88
Number of Stockholders of Record at January 31, 2004*			59,165

**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 maintains internal controls designed to provide reasonable assurance that the company's assets are protected from unauthorized use and that all transactions are executed in accordance with established authorizations and recorded properly. The internal controls are supported by written policies and guidelines and are complemented by a staff of internal auditors. Management believes that the internal controls in place at December 31, 2003, provide reasonable assurance that the books and records reflect the transactions of the company and there has been compliance with its policies and procedures.

The company's financial statements have been audited by Ernst & Young LLP, independent auditors selected by the Audit and Compliance Committee of the Board of Directors. 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.

Archie W. Dunham
Chairman of the Board

J.J. Mulva
President and
Chief Executive Officer

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

February 25, 2004

Report of Independent Auditors

The Board of Directors and Stockholders
ConocoPhillips

We have audited the accompanying consolidated balance sheets of ConocoPhillips as of December 31, 2003 and 2002, 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, 2003. 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 auditing standards generally accepted in the 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, 2003 and 2002, and the consolidated results of its operations and its cash flows for each of the three years in the period ended December 31, 2003, in conformity with accounting principles generally accepted in the United States.

As discussed in Note 2 to the consolidated financial statements, in 2003 ConocoPhillips adopted Statement of Financial Accounting Standards (SFAS) No. 143, "Accounting for Asset Retirement Obligations," SFAS No. 123, "Accounting for Stock-Based Compensation," and Financial Accounting Standards Board Interpretation No. 46, "Consolidation of Variable Interest Entities," and in 2001 ConocoPhillips changed its method of accounting for the costs of major maintenance turnarounds.

Ernst & Young LLP

Houston, Texas
February 25, 2004

Consolidated Income Statement

Years Ended December 31	Millions of Dollars		
	2003	2002	2001
Revenues			
Sales and other operating revenues*	**$104,196**	56,748	24,892
Equity in earnings of affiliates	**542**	261	41
Other income	**359**	192	97
Total Revenues	**105,097**	57,201	25,030
Costs and Expenses			
Purchased crude oil and products	**67,424**	37,823	13,708
Production and operating expenses	**7,208**	4,698	2,643
Selling, general and administrative expenses	**2,166**	1,950	613
Exploration expenses	**601**	592	306
Depreciation, depletion and amortization	**3,485**	2,223	1,344
Property impairments	**252**	177	26
Taxes other than income taxes*	**14,679**	6,937	2,740
Accretion on discounted liabilities	**145**	22	7
Interest and debt expense	**844**	566	338
Foreign currency transaction (gains) losses	**(36)**	24	11
Minority interests and preferred dividend requirements of capital trusts	**20**	48	53
Total Costs and Expenses	**96,788**	55,060	21,789
Income from continuing operations before income taxes and subsidiary equity transactions	**8,309**	2,141	3,241
Gain on subsidiary equity transactions	**28**	—	—
Income from continuing operations before income taxes	**8,337**	2,141	3,241
Provision for income taxes	**3,744**	1,443	1,640
Income From Continuing Operations	**4,593**	698	1,601
Income (loss) from discontinued operations	**237**	(993)	32
Income (loss) before cumulative effect of changes in accounting principles	**4,830**	(295)	1,633
Cumulative effect of changes in accounting principles	**(95)**	—	28
Net Income (Loss)	**$ 4,735**	(295)	1,661
Income (Loss) Per Share of Common Stock			
Basic			
Continuing operations	**$ 6.75**	1.45	5.46
Discontinued operations	**.35**	(2.06)	.11
Before cumulative effect of changes in accounting principles	**7.10**	(.61)	5.57
Cumulative effect of changes in accounting principles	**(.14)**	—	.10
Net Income (Loss)	**$ 6.96**	(.61)	5.67
Diluted			
Continuing operations	**$ 6.70**	1.44	5.43
Discontinued operations	**.35**	(2.05)	.11
Before cumulative effect of changes in accounting principles	**7.05**	(.61)	5.54
Cumulative effect of changes in accounting principles	**(.14)**	—	.09
Net Income (Loss)	**$ 6.91**	(.61)	5.63
Average Common Shares Outstanding (in thousands)			
Basic	**680,490**	482,082	292,964
Diluted	**685,433**	485,505	295,016
**Includes excise taxes on petroleum products sales:*	***$ 13,705***	*6,236*	*2,178*

See Notes to Consolidated Financial Statements.

Consolidated Balance Sheet

At December 31	Millions of Dollars	
	2003	2002
Assets		
Cash and cash equivalents	**$ 490**	307
Accounts and notes receivable (net of allowance of $43 million in 2003 and $48 million in 2002)	**3,606**	2,873
Accounts and notes receivable — related parties	**1,399**	1,507
Inventories	**3,957**	3,845
Prepaid expenses and other current assets	**876**	766
Assets of discontinued operations held for sale	**864**	1,605
Total Current Assets	**11,192**	10,903
Investments and long-term receivables	**7,258**	6,821
Net properties, plants and equipment	**47,428**	43,030
Goodwill	**15,084**	14,444
Intangibles	**1,085**	1,119
Other assets	**408**	519
Total Assets	**$ 82,455**	76,836
Liabilities		
Accounts payable	**$ 6,598**	5,949
Accounts payable — related parties	**301**	303
Notes payable and long-term debt due within one year	**1,440**	849
Accrued income and other taxes	**2,676**	1,991
Other accruals	**2,817**	3,075
Liabilities of discontinued operations held for sale	**179**	649
Total Current Liabilities	**14,011**	12,816
Long-term debt	**16,340**	18,917
Asset retirement obligations and accrued environmental costs	**3,603**	1,666
Deferred income taxes	**8,565**	8,361
Employee benefit obligations	**2,445**	2,755
Other liabilities and deferred credits	**2,283**	1,803
Total Liabilities	**47,247**	46,318
Company-Obligated Mandatorily Redeemable Preferred Securities of Phillips 66 Capital Trust II	**—**	350
Other Minority Interests	**842**	651
Common Stockholders' Equity		
Common stock (2,500,000,000 shares authorized at $.01 par value)		
Issued (2003 — 708,085,097 shares; 2002 — 704,354,839 shares)		
Par value	**7**	7
Capital in excess of par	**25,361**	25,178
Compensation and Benefits Trust (CBT) (at cost: 2003 — 25,301,314 shares; 2002 — 26,785,094 shares)	**(857)**	(907)
Accumulated other comprehensive income (loss)	**821**	(164)
Unearned employee compensation	**(200)**	(218)
Retained earnings	**9,234**	5,621
Total Common Stockholders' Equity	**34,366**	29,517
Total	**$ 82,455**	76,836

See Notes to Consolidated Financial Statements.

Consolidated Statement of Cash Flows

Years Ended December 31	Millions of Dollars		
	2003	2002	2001
Cash Flows From Operating Activities			
Income from continuing operations	**$ 4,593**	698	1,601
Adjustments to reconcile income from continuing operations to net cash provided by continuing operations			
Non-working capital adjustments			
Depreciation, depletion and amortization	**3,485**	2,223	1,344
Property impairments	**252**	177	26
Dry hole costs and leasehold impairment	**300**	307	99
Accretion on discounted liabilities	**145**	22	7
Acquired in-process research and development	**—**	246	—
Deferred taxes	**401**	142	513
Undistributed equity earnings	**(59)**	18	92
Gain on asset dispositions	**(211)**	(7)	(34)
Other	**(328)**	(32)	80
Working capital adjustments*			
Decrease in aggregate balance of accounts receivable sold	**(161)**	(22)	(174)
Decrease (increase) in other accounts and notes receivable	**(28)**	(401)	1,357
Decrease (increase) in inventories	**(24)**	200	(289)
Decrease (increase) in prepaid expenses and other current assets	**(105)**	(37)	50
Increase (decrease) in accounts payable	**345**	788	(1,004)
Increase (decrease) in taxes and other accruals	**562**	454	(142)
Net cash provided by continuing operations	**9,167**	4,776	3,526
Net cash provided by discontinued operations	**189**	202	33
Net Cash Provided by Operating Activities	**9,356**	4,978	3,559
Cash Flows From Investing Activities			
Acquisitions, net of cash acquired	**—**	1,180	80
Cash consolidated from adoption of FIN 46	**225**	—	—
Capital expenditures and investments, including dry hole costs	**(6,169)**	(4,388)	(3,016)
Proceeds from asset dispositions	**2,659**	815	262
Long-term advances to affiliates and other investments	**23**	(92)	(28)
Net cash used in continuing operations	**(3,262)**	(2,485)	(2,702)
Net cash used in discontinued operations	**(236)**	(99)	(68)
Net Cash Used in Investing Activities	**(3,498)**	(2,584)	(2,770)
Cash Flows From Financing Activities			
Issuance of debt	**348**	3,502	566
Repayment of debt	**(5,159)**	(4,592)	(945)
Redemption of preferred stock of subsidiary	**—**	(300)	—
Issuance of company common stock	**108**	44	51
Dividends paid on common stock	**(1,107)**	(684)	(403)
Other	**111**	(190)	(68)
Net cash used in continuing operations	**(5,699)**	(2,220)	(799)
Net Cash Used in Financing Activities	**(5,699)**	(2,220)	(799)
Effect of Exchange Rate Changes on Cash and Cash Equivalents	**24**	(9)	3
Net Change in Cash and Cash Equivalents	**183**	165	(7)
Cash and cash equivalents at beginning of year	**307**	142	149
Cash and Cash Equivalents at End of Year	**$ 490**	307	142

**Net of acquisition and disposition of businesses.*
See Notes to Consolidated Financial Statements.

Consolidated Statement of Changes in Common Stockholders' Equity

	Shares of Common Stock			Millions of Dollars							
				Common Stock				Accumulated Other Comprehensive Income (Loss)	Unearned Employee Compensation	Retained Earnings	Total
	Issued	Held in Treasury	Held in CBT	Par Value	Capital in Excess of Par	Treasury Stock	CBT				
December 31, 2000	306,380,511	23,142,005	27,849,430	$383	2,153	(1,156)	(943)	(100)	(263)	6,019	6,093
Net income										1,661	1,661
Other comprehensive income (loss)											
Minimum pension liability adjustment								(143)			(143)
Foreign currency translation								(14)			(14)
Unrealized loss on securities								(2)			(2)
Hedging activities								(4)			(4)
Equity affiliates:											
Foreign currency translation								(3)			(3)
Derivatives related								11			11
Comprehensive income											1,506
Cash dividends paid on common stock										(403)	(403)
Tosco acquisition	124,059,232			155	6,883						7,038
Distributed under incentive compensation and other benefit plans		(2,416,891)	(292,857)		33	118	9			(84)	76
Recognition of unearned compensation									26		26
Other										4	4
December 31, 2001	430,439,743	20,725,114	27,556,573	538	9,069	(1,038)	(934)	(255)	(237)	7,197	14,340
Net loss										(295)	(295)
Other comprehensive income (loss)											
Minimum pension liability adjustment								(93)			(93)
Foreign currency translation								182			182
Unrealized loss on securities								(3)			(3)
Hedging activities								(1)			(1)
Equity affiliates:											
Foreign currency translation								40			40
Derivatives related								(34)			(34)
Comprehensive loss											(204)
Cash dividends paid on common stock										(684)	(684)
ConocoPhillips merger	273,471,505	(19,852,674)		(531)	16,056	999				(562)	15,962
Distributed under incentive compensation and other benefit plans	443,591	(872,440)	(771,479)		53	39	27			(39)	80
Recognition of unearned compensation									19		19
Other										4	4
December 31, 2002	704,354,839	—	26,785,094	7	25,178	—	(907)	(164)	(218)	5,621	29,517
Net income										**4,735**	**4,735**
Other comprehensive income (loss)											
Minimum pension liability adjustment								**168**			**168**
Foreign currency translation								**637**			**637**
Unrealized gain on securities								**4**			**4**
Hedging activities								**7**			**7**
Equity affiliates:											
Foreign currency translation								**149**			**149**
Derivatives related								**20**			**20**
Comprehensive income											**5,720**
Cash dividends paid on common stock										**(1,107)**	**(1,107)**
Distributed under incentive compensation and other benefit plans	**3,730,258**		**(1,483,780)**		**183**		**50**				**233**
Recognition of unearned compensation									**18**		**18**
Other										**(15)**	**(15)**
December 31, 2003	**708,085,097**	**—**	**25,301,314**	**$ 7**	**25,361**	**—**	**(857)**	**821**	**(200)**	**9,234**	**34,366**

See Notes to Consolidated Financial Statements.

Notes to Consolidated Financial Statements

Note 1 — Accounting Policies

■ **Consolidation Principles and Investments —** Consolidation decisions are based on the risk, rewards and voting rights associated with our interest in an entity. Entities that are determined to be Variable Interest Entities (VIEs), as defined by Financial Accounting Standards Board (FASB) Interpretation No. 46, as revised, (FIN 46) will be consolidated if we are the primary beneficiary of that entity. For entities that are not VIEs under FIN 46, we consolidate majority-owned, controlled subsidiaries. The equity method is used to account for investments in affiliates in which we exert significant influence, generally having a 20 to 50 percent ownership interest. We also use the equity method for our 50.1 percent and 57.1 percent non-controlling interests in Petrozuata C.A. and Hamaca Holding LLC, respectively, located in Venezuela because the minority shareholders have substantive participating rights, under which all substantive operating decisions (e.g., annual budgets, major financings, selection of senior operating management, etc.) require joint approvals. The cost method is used when we do not have 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.

■ **Revenue Recognition —** Revenues associated with sales of crude oil, natural gas, natural gas liquids, petroleum and chemical products, and all other items are recorded when title passes to the customer. Revenues include the sales portion of contracts involving purchases and sales necessary to reposition supply to address location or quality or grade requirements (e.g., when we reposition crude by entering into a contract with a counterparty to sell crude in one location and purchase it in a different location) and sales related to purchase for resale activity. Revenues from the production of natural gas 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 non-recoverable through remaining production, are recognized as accounts receivable or accounts payable, as appropriate. Cumulative differences between volumes sold and entitlement volumes are 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.

■ **Reclassification —** Certain amounts in the 2002 and 2001 financial statements have been reclassified to conform with the 2003 presentation.

■ **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 the estimates and assumptions used.

■ **Cash Equivalents —** Cash equivalents are highly liquid short-term investments that are readily convertible to known amounts of cash and have original maturities within three months 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 are valued using the weighted-average-cost method, consistent with general industry practice. Merchandise inventories at our retail marketing outlets are valued using the first-in, first-out (FIFO) retail method, consistent with general industry practice.

■ **Derivative Instruments —** All derivative instruments are recorded on the balance sheet at fair value in either accounts and notes receivable, other assets, accounts payable, or other liabilities and deferred credits. Recognition 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 used as hedges are recognized immediately in earnings. For derivative instruments that are designated and qualify as a fair value hedge, the gains or losses from adjusting the derivative to its fair value will be immediately recognized in earnings and, to the extent the hedge is effective, offset the concurrent recognition of changes in the fair value of the hedged item. Gains or losses from derivative instruments that are designated and qualify as a cash flow hedge will be recorded on the balance sheet in accumulated other comprehensive income/(loss) until the hedged transaction is recognized in earnings; however, to the extent the change in the value of the derivative exceeds the change in the anticipated cash flows of the hedged transaction, the excess gains or losses will be recognized immediately in earnings.

In the consolidated 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 and products, interest and debt expense, foreign currency transaction gains/losses, depending on the purpose for issuing or holding the derivative.

■ **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 discovery of commercial reserves, leasehold costs are transferred 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 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. All exploratory wells are evaluated for economic viability within one year of well completion. Exploratory wells that discover potentially economic reserves that are in areas where a major capital expenditure would be required before production could begin, and where the economic viability of that major capital expenditure depends upon the successful completion of further exploratory work in the area, remain capitalized as long as the additional exploratory work is under way or firmly planned.

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 the cost of the acquisition 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.

■ **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 cost. 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, reporting units have been determined to be Worldwide Exploration and Production, Worldwide Refining and Worldwide 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 in the periods in which the determination of 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. 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, Statement of Financial Accounting Standards (SFAS) No. 69, "Disclosures about Oil and Gas Producing Activities," requires the use of prices and costs at the balance sheet date, with no projection of future changes in those assumptions.

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

- **Shipping and Handling Costs —** Our Exploration and Production segment includes shipping and handling costs in production and operating expenses, while the Refining and Marketing segment records shipping and handling costs in purchased crude oil and products. Freight costs billed to customers are recorded as a component of revenue.

- **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 which 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 retired or sold, the asset cost and related accumulated depreciation are eliminated, with any gain or loss reflected in 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 —** Effective January 1, 2003, the company adopted SFAS No. 143, "Accounting for Asset Retirement Obligations," which applies to legal obligations associated with the retirement and removal of long-lived assets. SFAS 143 requires entities to record the fair value of a liability for an asset retirement obligation in the period when it is incurred (typically when the asset is installed at the production location). Through December 31, 2002, the estimated undiscounted costs, net of salvage values, of dismantling and removing major oil and gas production and transportation facilities, including necessary site restoration, were accrued using either the unit-of-production or the straight-line method, which was used for certain regional production transportation assets that are expected to have a straight-line utilization pattern. See Note 2 — Changes in Accounting Principles 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 these expenditures are recorded on an undiscounted basis (unless acquired in a purchase business acquisition) 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.

- **Stock-Based Compensation —** Effective January 1, 2003, we voluntarily adopted the fair-value accounting method provided for under SFAS No. 123, "Accounting for Stock-Based Compensation." We used the prospective transition method provided under SFAS 123, 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 continue to be accounted for under Accounting Principles Board Opinion (APB) No. 25, "Accounting for Stock Issued to Employees," and related Interpretations. Because the exercise price of our employee stock options equals the market price of the underlying stock on the date of grant, no compensation expense is generally recognized under APB No. 25. The following table displays pro forma information as if the provisions of SFAS No. 123 had been applied to all employee stock options granted:

	2003	2002	2001
Net income (loss), as reported	**$4,735**	(295)	1,661
Add: Stock-based employee compensation expense included in reported net income, net of related tax effects	**50**	74	13
Deduct: Total stock-based employee compensation expense determined under fair-value based method for all awards, net of related tax effects	**78**	135	29
Pro forma net income (loss)	**$4,707**	(356)	1,645
Earnings per share:			
Basic — as reported	**$ 6.96**	(.61)	5.67
Basic — pro forma	**6.92**	(.74)	5.62
Diluted — as reported	**6.91**	(.61)	5.63
Diluted — pro forma	**6.87**	(.73)	5.58

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

- **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.

- **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. Diluted income per share of common stock includes the above, plus "in-the-money" stock options issued under our compensation plans. Treasury stock and shares held by the Compensation and Benefits Trust (CBT) are excluded from the daily weighted-average number of common shares outstanding in both calculations.

- **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.

- **Accounting for Sales of Stock by Subsidiary or Equity Investees** — We recognize a gain or loss upon the direct sale of 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

Accounting for Asset Retirement Obligations

Effective January 1, 2003, we adopted SFAS No. 143, "Accounting for Asset Retirement Obligations," which applies to legal obligations associated with the retirement and removal of long-lived assets. SFAS No. 143 requires entities to record the fair value of a liability for an asset retirement obligation in the period 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 is increased for the change in its present value each period, and the initial capitalized cost is depreciated over the useful life of the related asset.

Application of this new accounting principle resulted in an initial increase in net properties, plants and equipment of $1.2 billion and an asset retirement obligation liability increase of $1.1 billion. The cumulative effect of the change increased 2003 net income by $145 million (after reduction of income taxes of $21 million). The 2003 effect of the adoption increased income from continuing operations and net income for 2003 by $32 million, or $.05 per basic and diluted share.

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 are related to fixed-base offshore production platforms around the world and to production facilities and pipelines in Alaska.

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 have excluded it from our SFAS No. 143 estimates.

During 2003, our overall asset retirement obligation changed as follows:

	Millions of Dollars
Opening balance at January 1, 2003	$2,110
Accretion of discount	118
New obligations	43
Spending on existing obligations	(62)
Property dispositions	(95)
Foreign currency translation	109
Adjustment due to repeal of Norway Removal Grant Act	414
Other adjustments	48
Ending balance at December 31, 2003	$2,685

The following table presents the pro forma effects of the retroactive application of this change in accounting principle as if the principle had been adopted on January 1, 2001.

	Millions of Dollars Except Per Share Amounts		
	2003	2002	2001
Net income (loss)*	**$4,590**	(254)	1,712
Earnings per share			
Basic	**6.75**	(.53)	5.84
Diluted	**6.70**	(.52)	5.80

**Net income of $4,735 million for 2003 has been adjusted to remove the $145 million cumulative effect of the change in accounting principle attributable to SFAS No. 143.*

	Millions of Dollars
Pro forma asset retirement obligation	
At January 1, 2002	$1,171
At December 31, 2002	2,110

Consolidation of Variable Interest Entities

In January 2003, the FASB issued Interpretation No. 46, "Consolidation of Variable Interest Entities," (FIN 46) to expand existing accounting guidance about when a company should include in its consolidated financial statements the assets, liabilities and activities of another entity. In general, a variable interest entity (VIE) is a corporation, partnership, trust, or any other legal structure used for business purposes that either (a) does not have equity investors with voting rights or (b) has equity investors that do not provide sufficient financial resources for the entity to support its activities. FIN 46 requires a VIE to be consolidated by a company if that company is subject to a majority of the risk of loss from the VIE's activities, is entitled to receive a majority of the VIE's residual returns, or both (the company required to consolidate is called the primary beneficiary). It also requires deconsolidation of a VIE if a company is not the primary beneficiary of the VIE. The interpretation also requires disclosures about VIEs that a company does not have to consolidate, but in which it has a significant variable interest, and about any potential VIE when a company is unable to obtain the information necessary to confirm if an entity is a VIE or determine if a company is the primary beneficiary.

In December 2003, the FASB issued a revision to FIN 46 to clarify some of the provisions and to exempt certain entities from its guidance. Under the new guidance, special effective date provisions apply to enterprises that have fully or partially applied FIN 46 prior to the revision. The consolidation requirements of FIN 46, as revised, apply to all special purpose entities for periods ending after December 15, 2003. For all other types of variable interest entities the consolidation requirement applies for periods ending after March 15, 2004.

We adopted FIN 46 in the third quarter of 2003, with retroactive application to January 1, 2003, for VIEs involving synthetic leases and certain other financing structures as discussed below. We adopted FIN 46 for such VIEs because our work on these VIEs was complete and we believed the FASB's potential modifications of FIN 46 interpretive guidance was unlikely to change the primary beneficiary determination for these VIEs. We consolidated all VIEs created prior to February 1, 2003 (except as noted below), in which we concluded we were the primary beneficiary. In addition, we deconsolidated an entity where we determined we were not the primary beneficiary. The revision of FIN 46 did not change our accounting for any of the entities we consolidated or deconsolidated under FIN 46 in the third quarter. We continue to review FIN 46 and related guidance. If subsequent guidance or interpretation is different from our current understanding, it is possible that our determination of VIEs and primary beneficiaries could change.

There are two entities which could potentially be VIEs for which we were unable to obtain sufficient information to confirm that the entities were VIEs or to determine if we are the primary beneficiary. In February 2003, we entered into two agreements establishing separate guarantee facilities of $50 million each for two liquefied natural gas ships that were then under construction. 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 an aggregate of $100 million. Actual gross payments over the 20 years could exceed that amount to the extent cash is received by us. In September 2003, the first ship was delivered to its owner and the second ship is scheduled for delivery to its owner in 2005. We have determined that the agreements give us a variable interest in the two entities involved, but we do not have enough information regarding these entities and their activities to confirm that the entities are VIEs or to determine if we are the primary beneficiary. With respect to the first ship, the amount drawn under the guarantee facility at December 31, 2003, was less than $1 million. We continue to make efforts to obtain the information required to complete the FIN 46 analysis. We currently account for the guarantees under these agreements as guarantees and contingent liabilities. See Note 16 — Guarantees for additional information.

The adoption of FIN 46 for VIEs involving synthetic leases and certain other financing structures resulted in the following:

Consolidated VIEs

- We consolidated certain VIEs from which we lease certain ocean vessels, airplanes, refining assets, marketing sites and office buildings. The consolidation increased net properties, plants and equipment by $940 million and increased assets of discontinued operations held for sale by $726 million (both are collateral for the debt obligations); increased cash by $225 million; increased debt by $2.4 billion; increased minority interest by $90 million; reduced other accruals by $263 million, and resulted in a cumulative after-tax effect-of-adoption loss that decreased net income and common stockholders' equity by $240 million. However, during 2003 we exercised our option to purchase most of these assets and as a result, the leasing arrangements and our involvement with all but one of the associated VIEs was terminated. See Note 14 — Debt for more information about the resulting debt redemptions. At December 31, 2003, we continue to lease refining assets totaling $126 million, which are collateral for the debt obligations of $126 million from a VIE. Other than the obligation to make lease payments and residual value guarantees, the creditors of the VIE have no recourse to our general credit. In addition, we discontinued hedge accounting for an interest rate swap since it had been designated as a cash flow hedge of the variable interest rate component of a lease with a VIE that is now consolidated. At December 31, 2003, the fair market value of the swap was a liability of $13 million.
- Ashford Energy Capital S.A. continues to be consolidated in our financial statements under the provisions of FIN 46 because we are the primary beneficiary. In December 2001, in order to raise funds for general corporate purposes, Conoco and Cold Spring Finance S.a.r.l. formed Ashford Energy Capital S.A. through the contribution of a $1 billion Conoco 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 1.27 percent. The preferred return at December 31, 2003, was 2.48 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, 2003, 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, 2003, Ashford held

$1.6 billion of ConocoPhillips subsidiary notes and $25 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.

Unconsolidated VIEs

- Phillips 66 Capital II (Trust) was deconsolidated under the provisions of FIN 46 because ConocoPhillips is not the primary beneficiary. During 1997 in order to raise funds for general corporate purposes, we formed the Trust (a statutory business trust), in which we own all common beneficial interests. The Trust was created for the sole purpose of issuing mandatorily redeemable preferred securities to third-party investors and investing the proceeds thereof in an approximate equivalent amount of subordinated debt securities of ConocoPhillips. Application of FIN 46 required deconsolidation of the Trust, which increased debt by $361 million since the 8% Junior Subordinated Deferrable Interest Debentures due 2037 were no longer eliminated in consolidation, and the $350 million of mandatorily redeemable preferred securities were deconsolidated.

In 2003, we recorded a charge of $240 million (after an income tax benefit of $145 million) for the cumulative effect of adopting FIN 46. The effect of adopting FIN 46 increased 2003 income from continuing operations by $34 million, or $.05 per basic and diluted share. Excluding the cumulative effect, the adoption of FIN 46 increased net income by $139 million, or $.20 per basic and diluted share in 2003.

Stock-Based Compensation

Effective January 1, 2003, we adopted the fair-value accounting method provided for under SFAS No. 123, "Accounting for Stock-Based Compensation." We used the prospective transition method provided under SFAS 123, applying the fair-value accounting method and recognizing compensation expense for all stock options granted or modified after December 31, 2002. See Note 1 — Accounting Policies and Note 22 — Employee Benefit Plans for additional information.

Other

Effective January 1, 2003, we adopted SFAS No. 145, "Rescission of FASB Statements No. 4, 44, and 64, Amendment of FASB Statement No. 13, and Technical Corrections." The adoption of SFAS No. 145 requires that gains and losses on extinguishments of debt no longer be presented as extraordinary items in the income statement. Accordingly, losses from the extinguishment of debt of $16 million (after reduction for income taxes of $8 million), previously reported as an extraordinary item in 2002, have been reclassified as a $24 million charge to other income with the tax benefit reclassified to provision for income taxes. Similarly, in 2001, a loss from the early retirement of debt of $10 million (after reduction for income taxes of $4 million), has been reclassified as a $14 million charge to other income with the tax benefit reclassified to provision for income taxes.

In December 2003, the FASB revised and reissued SFAS No. 132 (revised 2003), "Employer's Disclosures about Pensions and Other Postretirement Benefits — an amendment of FASB Statements No. 87, 88 and 106." While requiring certain new disclosures, the new Standard does not change the measurement or recognition of employee benefit plans. We adopted the provisions of this Standard effective December 2003, except for certain provisions regarding disclosure of information about estimated future benefit payments which are not required until periods ending after December 15, 2004.

Effective January 1, 2001, the company changed its method of accounting for the costs of major maintenance turnarounds from the accrue-in-advance method to the expense-as-incurred method to reflect the impact of a turnaround in the period that it occurs. The new method is preferable because it results in the recognition of costs at the time obligations are incurred. The cumulative effect of this accounting change increased net income in 2001 by $28 million (after reduction for income taxes of $15 million).

Note 3 — Merger of Conoco and Phillips

On August 30, 2002, Conoco and Phillips combined their businesses by merging with separate acquisition subsidiaries of ConocoPhillips (the merger). As a result, each company became a wholly owned subsidiary of ConocoPhillips. For accounting purposes, Phillips was treated as the acquirer of Conoco, and ConocoPhillips was treated as the successor of Phillips. Conoco's operating results have been included in ConocoPhillips' consolidated financial statements since the merger date.

Immediately after the closing of the merger, former Phillips stockholders held approximately 56 percent of the outstanding shares of ConocoPhillips common stock, while former Conoco stockholders held approximately 44 percent. ConocoPhillips common stock, listed on the New York Stock Exchange under the symbol "COP," began trading on September 3, 2002.

The primary reasons for the merger and the principal factors that contributed to a purchase price that resulted in the recognition of goodwill were:

- The combination of Conoco and Phillips would create a stronger, major, integrated oil company with the benefits of increased size and scale, improving the stability of the combined business' earnings in varying economic and market climates;
- ConocoPhillips would emerge with a global presence in both upstream and downstream petroleum businesses, increasing its overall international presence to over 40 countries while maintaining a strong domestic base; and
- Combining the two companies' operations would provide significant synergies and related cost savings, and improve future access to capital.

The $16 billion purchase price attributed to Conoco for accounting purposes was based on an exchange of Conoco shares for ConocoPhillips common shares. ConocoPhillips issued approximately 293 million shares of common stock and approximately 23.3 million of employee stock options in exchange for 627 million shares of Conoco common stock and 49.8 million Conoco stock options. The common stock was valued at $53.15 per share, which was Phillips' average common stock price over the two-day trading period immediately before and after the November 18, 2001, public announcement of the transaction. The

Conoco stock options, the fair value of which was determined using the Black-Scholes option-pricing model, were exchanged for ConocoPhillips stock options valued at $384 million. Transaction-related costs, included in the purchase price, were $78 million.

The allocation of the purchase price to specific assets and liabilities was based, in part, upon an outside appraisal of the fair value of Conoco's assets. The following table summarizes the final purchase price allocation of the fair values of the assets acquired and liabilities assumed as of August 30, 2002:

	Millions of Dollars
Cash and cash equivalents	$ 1,250
Accounts and notes receivable	2,871
Inventories	1,615
Prepaid expenses and other current assets	327
Investments and long-term receivables	2,985
Properties, plants and equipment (including $300 million of land)	18,842
Goodwill	12,721
Intangibles	554
In-process research and development	246
Other assets	322
Total assets	$41,733
Accounts payable	$ 2,876
Notes payable and long-term debt due within one year	3,101
Accrued income and other taxes	1,471
Other accruals	1,636
Long-term debt	8,930
Accrued dismantlement, removal and environmental costs	594
Deferred income taxes	3,473
Employee benefit obligations	1,566
Other liabilities and deferred credits	1,385
Minority interests	648
Common stockholders' equity	16,053
Total liabilities and equity	$41,733

Goodwill and certain identifiable intangible assets recorded in the acquisition are not subject to amortization. However, goodwill and intangible assets are tested periodically for impairment as is required by SFAS No. 142, "Goodwill and Other Intangible Assets."

The acquired intangible assets include $441 million assigned to marketing tradenames, which are not subject to amortization, $95 million assigned to refining technology, with a weighted-average amortization period of 12 years, and $18 million assigned to other intangible assets, with a weighted-average amortization period of eight years.

We assigned the Conoco goodwill to specific reporting units in the fourth quarter of 2003. Previously, it had all been reported as part of Corporate and Other. Included in the $12,721 million of goodwill is $3,841 million attributable to recording a liability required for deferred taxes under purchase accounting. This, and the remaining goodwill of $8,880 million, was assigned to reporting units based on the benefits received by the units from the synergies and strategic advantages of the merger. The $12,721 million of goodwill has been allocated to three reporting units. See Note 11 — Goodwill and Intangibles for additional information. None of the goodwill is deductible for tax purposes. During 2003, the balance of goodwill was adjusted upward by $642 million, primarily due to revisions in the valuation of properties, plants and equipment, and assumed contingent liabilities.

The purchase price allocation included $246 million of in-process research and development costs related to Conoco's natural gas-to-liquids and other technologies. In accordance with FASB Interpretation No. 4, "Applicability of FASB Statement No. 2 to Business Combinations Accounted for by the Purchase Method," the value assigned to the research and development activities was charged to selling, general and administrative expenses in the Emerging Businesses segment at the date of the merger, as these research and development costs had no alternative future use.

Merger-related items that reduced our 2003 and 2002 income from continuing operations were:

	Millions of Dollars			
	Before-Tax		After-Tax	
	2003	2002	**2003**	2002
Write-off of acquired in-process research and development costs	**$ —**	246	**—**	246
Restructuring charges (see Note 5)	**240**	422	**131**	253
Incremental seismic contract costs	**—**	35	**—**	22
Transition costs	**110**	55	**92**	36
Total	**$350**	758	**223**	557

In total, these items reduced 2003 and 2002 income from continuing operations by $223 million and $557 million, respectively ($.33 per share and $1.15 per share on a diluted basis).

The following pro forma summary presents information as if the merger had occurred at the beginning of each period presented, and includes for 2002 the $557 million effect of the merger-related items mentioned above.

	Millions of Dollars Except Per Share Amounts	
	2002	2001
Revenues	$81,433	79,554
Income from continuing operations	918	3,635
Net income (loss)	(70)	4,072
Income from continuing operations per share of common stock		
Basic	1.36	5.39
Diluted	1.34	5.32
Net income (loss) per share of common stock		
Basic	(.10)	6.04
Diluted	(.10)	5.97

During 2001, both Phillips and Conoco entered into other significant transactions that are not reflected in each of their historical income statements for the full year 2001. The pro forma results have been prepared as if the Phillips' September 14, 2001, acquisition of Tosco Corporation (Tosco) (see Note 6 — Acquisition of Tosco Corporation) and Conoco's July 16, 2001, $4.6 billion acquisition of Gulf Canada Resources Limited occurred on January 1, 2001. Gulf Canada Resources Limited was a Canadian-based independent exploration and production company with primary operations in Western Canada, Indonesia, the Netherlands and Ecuador.

The pro forma results reflect the following:

- Recognition of depreciation and amortization based on the preliminary allocated purchase price of the properties, plants and equipment acquired;
- Adjustment of interest for the amortization of the fair-value adjustment to debt;
- Cessation of the amortization of deferred gains not recognizable in the purchase price allocation;

- Accretion of discount on environmental accruals recorded at net present value; and
- Various other adjustments to conform Conoco's accounting policies to ConocoPhillips'.

The pro forma adjustments use estimates and assumptions based on currently available information. Management believes that the estimates and assumptions are reasonable, and that the significant effects of the transactions are properly reflected.

The pro forma information does not reflect any anticipated synergies that might be achieved from combining the operations. The pro forma information is not intended to reflect the actual results that would have occurred had the companies been combined during the periods presented. This pro forma information is not intended to be indicative of the results of operations that may be achieved by ConocoPhillips in the future.

Note 4 — Discontinued Operations

During 2002 and 2003, we disposed of, or had committed to a plan to dispose of, certain U.S. retail and wholesale marketing assets, certain U.S. refining and related assets, certain U.S. midstream natural gas gathering and processing assets, and exploration and production assets in the Netherlands. Some of these planned dispositions were mandated by the FTC as a condition of the merger. For reporting purposes, these operations are classified as discontinued operations, and in Note 28 — Segment Disclosures and Related Information, these operations are included in Corporate and Other.

FTC-Mandated Divestitures

In the fourth quarter of 2002, we sold our propane terminal assets at Jefferson City, Missouri, and East St. Louis, Illinois.

During 2003 we sold:

- Our Woods Cross business unit, which includes the Woods Cross, Utah, refinery; the Utah, Idaho, Montana, and Wyoming Phillips-branded motor fuel marketing operations (both retail and wholesale) and associated assets; and a refined products terminal in Spokane, Washington;
- Certain midstream natural gas gathering and processing assets in southeast New Mexico, and certain midstream natural gas gathering assets in West Texas; and
- Our Commerce City, Colorado, refinery, and related crude oil pipelines, and our Colorado Phillips-branded motor fuel marketing operations (both retail and wholesale).

As a result, all asset dispositions mandated by the FTC as a condition of the merger have been completed.

Other Dispositions

In the fourth quarter of 2002, we committed to and initiated a plan to dispose of 3,200 marketing sites that did not fit into our long-range plans. In connection with the anticipated sale of these retail sites, we recorded charges in 2002 totaling $1,412 million before-tax, $1,008 million after-tax, primarily related to the impairment of properties, plants and equipment ($249 million); goodwill ($257 million); intangible asset ($429 million); and provisions for losses and penalties associated with various operating lease commitments ($477 million).

The intangible asset represented the Circle K tradename. Properties, plants and equipment included land, buildings and equipment of owned retail sites and leasehold improvements of leased sites. Fair value determinations were based on estimated sales prices for comparable sites.

The provisions for losses and penalties associated with various operating lease commitments included obligations for residual value guarantee deficiencies, and future minimum rental payments that existed prior to the commitment date that would continue after the exit plan is completed with no economic benefit. It also included penalties incurred to cancel the contractual arrangements.

In the third quarter of 2003, we concluded the sale of all of our Exxon-branded marketing assets in New York and New England, including contracts with independent dealers and marketers. Approximately 230 of the 3,200 sites were included in this package.

In the fourth quarter of 2003, we completed the sale of The Circle K Corporation and its subsidiaries. The transaction included about 1,660 retail marketing outlets in 16 states and the Circle K brand, as well as the assignment of the franchise relationship with more than 350 franchised and licensed stores. In January 2004, we signed agreements to sell our Mobil-branded marketing assets on the East Coast in two separate transactions. Assets in the packages include 104 company-owned and operated sites, and 352 dealer sites. Each of the transactions is expected to close in the second quarter of 2004. Discussions are under way with potential buyers for the remaining sites, and we expect to complete the sales of these assets during 2004. Based on disposals completed and signed agreements as of December 31, 2003, we recognized an additional charge in 2003 of approximately $96 million before-tax, $11 million after-tax.

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

	Millions of Dollars		
	2003	2002	2001
Sales and other operating revenues from discontinued operations	**$ 8,076**	7,406	2,670
Income (loss) from discontinued operations before-tax	**$ 317**	(1,387)	47
Income tax expense (benefit)	**80**	(394)	15
Income (loss) from discontinued operations	**$ 237**	(993)	32

Major classes of assets and liabilities of discontinued operations held for sale at December 31 were as follows:

	Millions of Dollars	
	2003	2002
Assets		
Inventories	**$ —**	211
Other current assets	**—**	136
Net properties, plants and equipment	**857**	1,178
Intangibles	**—**	23
Other assets	**7**	57
Assets of discontinued operations	**$ 864**	1,605
Liabilities		
Accounts payable and other current liabilities	**$ —**	331
Long-term debt	**—**	34
Asset retirement obligations and accrued environmental costs	**—**	86
Deferred income taxes, other liabilities and deferred credits	**179**	198
Liabilities of discontinued operations	**$ 179**	649

Note 5 — Restructuring

In 2002, as a result of the merger, we began a restructuring program to capture the benefits of combining Conoco and Phillips by eliminating redundancies, consolidating assets, and sharing common services and functions across regions. In connection with this program, the company recorded accruals in 2002 totaling $770 million for anticipated employee severance payments and incremental pension and medical plan benefit costs associated with the work force reductions, site closings, and Conoco employee relocations. Of the total 2002 accrual, $337 million was reflected in the Conoco purchase price allocation as an assumed liability, and $422 million ($253 million after-tax) related to Phillips was reflected in selling, general and administrative expense and production and operating expense, and $11 million before-tax was included in discontinued operations.

Included in the total accruals of $770 million was $172 million related to pension and other post-retirement benefits that will be paid in conjunction with other retirement benefits over a number of future years. The table below summarizes the balance of the 2002 accrual of $598 million, which consists of severance related benefits to be provided to approximately 2,900 employees worldwide and other merger related expenses. By the end of 2002, approximately 775 employees had been terminated. Changes in the 2002 severance related accrual balance are summarized below.

	Millions of Dollars		
	2002 Accruals	Benefit Payments	Reserve at December 31, 2002
Conoco	$297	(191)	106
Phillips	301	(32)	269
Total	$ 598	(223)	375

In 2003, as individual components of the restructuring program were finalized, we recorded an additional $350 million for severance-related benefits, site closings, Conoco employee relocation costs, and pension and other postretirement benefits. Of this total, $110 million was reflected as a purchase price adjustment in the consolidated financial statements and $240 million was reflected in selling, general and administrative expense and production and operating expense. Included in the total 2003 additional accruals of $350 million was a $118 million expense related to pension and other postretirement benefits that will be paid in conjunction with other retirement benefits over a number of future years. This is reported as part of our employee benefit plan obligations. A roll-forward of activity during 2003 is provided below for the non-pension portion of the accrual, which primarily consists of severance-related benefits to be provided to approximately 3,900 employees worldwide, most of whom are in the United States, as well as other merger related expenses.

	Millions of Dollars			
	Reserve at December 31, 2002	Twelve Months 2003 Accruals	Twelve Months 2003 Payments	Reserve at December 31, 2003
Conoco	$106	107	(130)	83
Phillips	269	125	(230)	164
Total	$375	232	(360)	247

The restructuring liability at December 31 of $247 million is expected to be expended by the end of the first quarter of 2004; except for $53 million, classified as long-term. The remaining $194 million is included in other accruals in the current liabilities section of the balance sheet. Approximately 2,225 employees were terminated during 2003 and approximately 3,000 employees have been terminated since the restructuring program was implemented.

Note 6 — Acquisition of Tosco Corporation

On September 14, 2001, Tosco was merged with a subsidiary of ConocoPhillips, as a result of which we became the owner of 100 percent of the outstanding common stock of Tosco. Tosco's results of operations have been included in our consolidated financial statements since that date. Tosco's operations included seven U.S. refineries with a total crude oil capacity of 1.31 million barrels per day; one 75,000-barrel-per-day refinery located in Cork, Ireland; and various marketing, transportation, distribution and corporate assets.

The primary reasons for our acquisition of Tosco, and the primary factors that contributed to a purchase price that resulted in recognition of goodwill, are:

- The Tosco operations would deliver earnings prospects, and potential strategic and other benefits;
- Combining the two companies' operations would provide significant cost savings;
- Adding Tosco to our Refining and Marketing (R&M) operations would give the segment the size, scale and resources to compete more effectively;
- The merger would transform us into a stronger, more integrated oil company with the benefits of increased size and scale, improving the stability of the combined business' earnings in varying economic and market climates;
- The combined company would have a stronger balance sheet, improving its access to capital in the future; and
- The increased cash flow and access to capital resulting from the Tosco acquisition would allow us to pursue other opportunities in the future.

The allocation of the purchase price to specific assets and liabilities was based, in part, upon an outside appraisal of Tosco's long-lived assets. Goodwill and indefinite-lived intangible assets recorded in the acquisition are not subject to amortization, but the goodwill and intangible assets will be tested periodically for impairment as required by SFAS No. 142, "Goodwill and Other Intangible Assets."

During the third quarter of 2002, we concluded:

- The outside appraisal of the long-lived assets;
- The determination of the fair value of all other Tosco assets and liabilities;

- The tax basis calculation of Tosco's assets and liabilities and the related deferred tax liabilities; and
- The allocation of Tosco goodwill to reporting units within the R&M operating segment.

The resulting adjustments to the purchase price allocation made in 2002 increased goodwill by $341 million. The more significant adjustments to goodwill were a $247 million reduction in the value of refinery air emission permits to reflect a more appropriate appraisal methodology, a $70 million liability recorded for Tosco Long-Term Incentive Plan performance units, and a $69 million increase in deferred tax liabilities, resulting primarily from an updated analysis of the tax bases of Tosco's assets and liabilities. All other adjustments in the aggregate reduced goodwill by $45 million.

Tosco Long-Term Incentive Plan performance units were derivative financial instruments tied to our stock price and were marked-to-market each reporting period. The resulting gains or losses from these mark-to-market adjustments were reported in other income in the consolidated income statement. In October 2002, we and former Tosco executives negotiated a complete cancellation of the performance units in exchange for a cash payment to the former executives. During 2002, we recorded gains totaling $38 million, after-tax, as this liability was marked-to-market each reporting period and eventually settled.

Note 7 — Subsidiary Equity Transactions

ConocoPhillips, through various affiliates, and its unaffiliated co-venturers received final approvals from authorities in June 2003 to proceed with the natural gas development phase of the Bayu-Undan project in the Timor Sea. The natural gas development phase of the project includes a pipeline from the offshore Bayu-Undan field to Darwin, Australia, and a liquefied natural gas facility, also located in Darwin. The pipeline portion of the project is owned and operated by an unincorporated joint venture, while the liquefied natural gas facility is owned and operated by Darwin LNG Pty Ltd (DLNG). Both of these entities are consolidated subsidiaries of ConocoPhillips.

In June 2003, as part of a broad Bayu-Undan ownership interest re-alignment with co-venturers, these entities issued equity and sold interests to the co-venturers (as described below), which resulted in a gain of $28 million before-tax, $25 million after-tax, in 2003. This non-operating gain is shown in the consolidated statement of income in the line item entitled "Gain on subsidiary equity transactions."

DLNG — DLNG issued 118.9 million shares of stock, valued at 1 Australian dollar per share, to co-venturers for 118.9 million Australian dollars ($76.2 million U.S. dollars), reducing our ownership interest in DLNG from 100 percent to 56.72 percent. The transaction resulted in a before-tax gain of $21 million in the consolidated financial statements. Deferred income taxes were not recognized because this was an issuance of common stock and therefore not taxable.

Unincorporated Pipeline Joint Venture — The co-venturers purchased pro-rata interests in the pipeline assets held by ConocoPhillips Pipeline Australia Pty Ltd for $26.6 million U.S. dollars and contributed the purchased assets to the unincorporated joint venture, reducing our ownership interest from 100 percent to 56.72 percent. The transaction resulted in a before-tax gain of $7 million. A deferred tax liability of $1.3 million was recorded in connection with the transaction.

Note 8 — Inventories

Inventories at December 31 were:

	Millions of Dollars	
	2003	2002
Crude oil and petroleum products	**$ 3,467**	3,395
Materials, supplies and other	**490**	450
	$ 3,957	3,845

Inventories valued on a LIFO basis totaled $3,224 million and $3,349 million at December 31, 2003 and 2002, respectively. The remainder of our inventories are valued under various methods, including FIFO and weighted average. The excess of current replacement cost over LIFO cost of inventories amounted to $1,421 million and $1,803 million at December 31, 2003 and 2002, respectively.

During 2003, certain inventory quantity reductions caused a liquidation of LIFO inventory values. This liquidation increased income from continuing operations by $24 million, of which $22 million was attributable to our R&M segment.

In the fourth quarter of 2001, the company recognized a $42 million before-tax, $27 million after-tax, lower-of-cost-or-market write-down of its petroleum products inventory.

Note 9 — Investments and Long-Term Receivables

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

	Millions of Dollars	
	2003	2002
Investments in and advances to affiliated companies	**$ 6,258**	5,900
Long-term receivables	**476**	526
Other investments	**524**	395
	$ 7,258	6,821

At December 31, 2003, retained earnings included $835 million related to the undistributed earnings of affiliated companies, and distributions received from affiliates were $496 million, $313 million and $163 million in 2003, 2002 and 2001, respectively.

Equity Investments

We own or owned investments in chemicals, heavy-oil projects, oil and gas transportation, coal mining and other industries. The affiliated companies for which we use the equity method of accounting include, among others, the following companies:

- Chevron Phillips Chemical Co. LLC (CPChem) — 50 percent ownership interest — manufactures and markets petrochemicals and plastics;

- Duke Energy Field Services, LLC (DEFS) — 30.3 percent ownership interest — owns and operates gas plants, gathering systems, storage facilities and fractionation plants;
- Hamaca Holding LLC — 57.1 percent non-controlling ownership interest — currently building facilities to extract extra heavy crude oil from reserves in Eastern Venezuela;
- Merey Sweeney L.P. (MSLP) — 50 percent ownership interest — processes heavy crude oil into intermediate products for the Sweeney, Texas, refinery;
- Petrovera Resources Limited — 46.7 percent ownership interest — owns, operates and finances heavy-oil producing properties in Western Canada. On February 18, 2004, we sold our interest in this joint venture; and
- Petrozuata C.A. — 50.1 percent non-controlling ownership interest — produces extra heavy crude oil and upgrades it into medium grade crude oil at Jose on the northern coast of Venezuela.

Summarized 100 percent financial information for equity-basis investments in affiliated companies, combined, was as follows:

2003	Millions of Dollars			
	DEFS	CPChem	Other Equity Companies	Total
Revenues	**$8,886**	**7,018**	**13,873**	**29,777**
Income before income taxes	**268**	**12**	**1,753**	**2,033**
Net income	**214**	**7**	**1,274**	**1,495**
Current assets	**1,201**	**1,636**	**6,163**	**9,000**
Noncurrent assets	**5,313**	**4,606**	**23,776**	**33,695**
Current liabilities	**1,274**	**1,184**	**5,909**	**8,367**
Noncurrent liabilities	**2,376**	**1,298**	**7,629**	**11,303**

2002	Millions of Dollars			
	DEFS	CPChem	Other Equity Companies	Total
Revenues	$5,992	5,473	5,378	16,843
Income (loss) before income taxes	(37)	(24)	776	715
Net income (loss)	(47)	(30)	751	674
Current assets	1,182	1,561	5,783	8,526
Noncurrent assets	5,417	4,548	14,386	24,351
Current liabilities	1,504	1,051	5,046	7,601
Noncurrent liabilities	2,320	1,307	9,713	13,340

2001	Millions of Dollars			
	DEFS	CPChem	Other Equity Companies	Total
Revenues	$8,321	6,010	1,555	15,886
Income (loss) before income taxes	367	(431)	607	543
Net income (loss)	364	(480)	414	298

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.

Duke Energy Field Services, LLC

DEFS owns and operates gas plants, gathering systems, storage facilities and fractionation plants. At December 31, 2003, the book value of our common investment in DEFS was $212 million. Our 30.3 percent share of the net assets of DEFS was $831 million. This basis difference of $619 million is being amortized on a straight-line basis through 2014 consistent with the remaining estimated useful lives of DEFS' properties, plants and equipment. Included in net income for 2003, 2002 and 2001 was after-tax income of $36 million, $35 million and $36 million, respectively, representing the amortization of the basis difference.

DEFS supplies a substantial 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.

On December 31, 2003, DEFS redeemed the remaining $75 million of its preferred member interests. We received our 30.3 percent share, a $23 million distribution representing the return of our preferred member interests.

Chevron Phillips Chemical Company LLC

CPChem manufactures and markets petrochemicals and plastics. At December 31, 2003, the book value of our investment in CPChem was $1,917 million. Our 50 percent share of the total net assets of CPChem was $1,755 million. This basis difference of $162 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.

Note 10 — Properties, Plants and Equipment

The company's investment in properties, plants and equipment (PP&E), with accumulated depreciation, depletion and amortization (Accum. DD&A), at December 31 was:

	Millions of Dollars					
	2003			2002		
	Gross PP&E	Accum. DD&A	Net PP&E	Gross PP&E	Accum. DD&A	Net PP&E
E&P	**$42,358**	**10,837**	**31,521**	36,884	8,600	28,284
Midstream	**944**	**87**	**857**	903	16	887
R&M	**16,469**	**2,870**	**13,599**	15,605	2,765	12,840
Chemicals	**—**	**—**	**—**	—	—	—
Emerging Businesses	**1,013**	**214**	**799**	690	5	685
Corporate and Other	**1,055**	**403**	**652**	477	143	334
	$61,839	**14,411**	**47,428**	54,559	11,529	43,030

Our investment in PP&E is recorded at cost. PP&E acquired in mergers and acquisitions is recorded at its fair market value at the time of the merger or acquisition. Effective January 1, 2003, we adopted SFAS No. 143, "Accounting for Asset Retirement Obligations," which applies to legal obligations associated with the retirement and removal of long-lived assets. SFAS No. 143 requires entities to record the fair value of a liability for an asset retirement obligation in the period 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 PP&E. Over time, the liability is increased for the change in its present value each period, and the initial capitalized cost is depreciated over the useful life of the related asset. Application of this new accounting principle resulted in an initial increase in net PP&E of $1.2 billion.

In June 2001, the FASB issued SFAS No. 141, "Business Combinations," and SFAS No. 142, "Goodwill and Other Intangible Assets," which became effective on July 1, 2001, and January 1, 2002, respectively. The Securities and Exchange Commission (SEC) has requested the Emerging Issues Task Force (EITF) to consider the issue of whether SFAS Nos. 141 and 142 require interests held under oil, gas and mineral leases to be separately classified as intangible assets on the balance sheets of companies in the extractive industries. Historically, in accordance with SFAS No. 19, "Financial Accounting and Reporting by Oil and Gas Producing Companies," we have capitalized the cost of oil and gas leasehold interests and, consistent with industry practice, reported these assets as part of tangible E&P properties, plants and equipment.

If such interests were deemed to be intangible assets by the EITF, mineral rights to extract oil and gas for both proved and unproved properties would be classified separately from E&P properties, plants and equipment as intangible assets on our balance sheet. This interpretation by the EITF would only affect the classification of oil and gas mineral rights on our balance sheet and would not affect total assets, net worth, results of operations or cash flows.

E&P properties, plants and equipment at December 31, 2003 and 2002, included approximately $10.5 billion and $10.8 billion, respectively, of mineral rights to extract oil and gas, net of accumulated depletion, that would be reclassified on the balance sheet as intangible assets, if the interpretation that the SEC requested the EITF to consider was applied. We plan to continue to classify oil and gas mineral rights as E&P properties, plants and equipment until further guidance is provided by the EITF.

Note 11 — Goodwill and Intangibles

Changes in the carrying amount of goodwill are as follows:

	Millions of Dollars			
	E&P	R&M	Corporate	Total
Balance at December 31, 2001	$ 15	2,266	—	2,281
Acquired (merger of Conoco and Phillips)	—	—	12,079	12,079
Valuation and other adjustments	—	341	—	341
Allocated to discontinued operations	—	(257)	—	(257)
Balance at December 31, 2002	$ 15	2,350	12,079	14,444
Valuation and other adjustments	**3**	**7**	**630**	**640**
Allocation to reporting units	**11,166**	**1,543**	**(12,709)**	**—**
Balance at December 31, 2003	**$11,184**	**3,900***	**—**	**15,084**

**Consists of two reporting units: Worldwide Refining ($2,000) and Worldwide Marketing ($1,900).*

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, 2003			
Refining technology related	**$101**	**9**	**92**
Other*	**57**	**29**	**28**
	$158	**38**	**120**
Balance at December 31, 2002			
Refining technology related	$ 95	1	94
Other*	60	22	38
	$155	23	132

**Primarily related to seismic technology, land rights, supply contracts and licenses.*

Indefinite-Lived Intangible Assets	
Balance at December 31, 2003	
Tradenames	**$604**
Refinery air and operating permits	**315**
Other*	**46**
	$965
Balance at December 31, 2002	
Tradenames	$669
Refinery air and operating permits	315
Other*	3
	$987

**Primarily pension related.*

Amortization expense related to the intangible assets above for the year ended December 31, 2003, was $17 million. The estimated amortization expense for the next five years is approximately $20 million per year. Amortization expense for the year ended December 31, 2002, was not material.

Note 12 — Property Impairments

During 2003, 2002 and 2001, we recognized the following impairment charges:

	Millions of Dollars		
	2003	2002	2001
E&P			
United States	**$ 65**	12	3
International	**180**	37	23
R&M			
Tradenames	**—**	102	—
Retail site leasehold improvements	**—**	26	—
Transportation	**2**	—	—
Corporate and Other	**5**	—	—
	$252	177	26

2003

The E&P segment recognized property impairments of $245 million in 2003. These impairments were the result of:

- The write-down to market value of properties planned for disposition;
- Properties failing to meet recoverability tests; and
- International tax law changes affecting asset removal costs.

2002

Our E&P segment recognized impairments of $49 million on four fields in 2002. Impairment of the Janice field in the U.K. North Sea was triggered by its sale, while the Viscount field in the U.K. North Sea was impaired following an evaluation of development drilling results. Sales of properties in Alaska and offshore California resulted in the remaining E&P impairments in 2002.

We initiated a plan in late 2002 to sell a substantial portion of our R&M retail sites. The planned dispositions will result in a reduction of the amount of gasoline volumes marketed under our "76" tradename. As a result, the carrying value of the "76" tradename was impaired, with the $102 million impairment determined by an analysis of the discounted cash flows based on the gasoline volumes projected to be sold under the brand name after the planned dispositions, compared with the volumes being sold prior to the dispositions. We also impaired the carrying value of certain leasehold improvements associated with leased retail sites that are held for use by comparing the guaranteed residual values and leasehold improvements with current market values of the related assets.

See Note 4 — Discontinued Operations for information regarding the impairments recognized in 2002 in connection with the anticipated sale of certain assets mandated by the FTC, and the planned sale of a substantial portion of the company's retail marketing operations.

2001

In the second quarter of 2001, we committed to a plan to sell our 12.5 percent interest in the Siri oil field, offshore Denmark, triggering a write-down of the field's assets to fair market value. The sale closed in early 2002. We also recorded a property impairment on a crude oil tanker that was sold in the fourth quarter of 2001.

Note 13 — Asset Retirement Obligations and Accrued Environmental Costs

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

	Millions of Dollars	
	2003	2002
Asset retirement obligations	**$2,685**	1,065
Accrued environmental costs	**1,119**	743
Total asset retirement obligations and accrued environmental costs	**3,804**	1,808
Asset retirement obligations and accrued environmental costs due within one year*	**(201)**	(142)
Long-term asset retirement obligations and accrued environmental costs	**$3,603**	1,666

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

Asset Retirement Obligations

For information on the company's adoption of SFAS 143 and related disclosures, see Note 2 — Changes in Accounting Principles.

Accrued Environmental Costs

Total environmental accruals at December 31, 2003 and 2002, were $1,119 million and $743 million, respectively. The 2003 increase in total accrued environmental costs primarily resulted from evaluation of Conoco environmental liabilities during the purchase price allocation period.

We had accrued environmental costs of $625 million and $427 million at December 31, 2003 and 2002, respectively, primarily related to cleanup at domestic refineries and underground storage tanks at U.S. service stations, and remediation activities required by the state of Alaska at exploration and production sites formerly owned by Atlantic Richfield Company. We had also accrued in Corporate and Other $367 million and $246 million of environmental costs associated with non-operating sites at December 31, 2003 and 2002, respectively. In addition, $127 million and $70 million were included at December 31, 2003 and 2002, 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 our 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 $908 million at December 31, 2003. The expected future undiscounted payments related to the portion of the accrued environmental costs that have been discounted are: $131 million in 2004, $121 million in 2005, $88 million in 2006, $72 million in 2007, $67 million in 2008, and $596 million for all future years after 2008.

Note 14 — Debt

Long-term debt at December 31 was:

	Millions of Dollars	
	2003	2002
9 3/8% Notes due 2011	**$ 350**	350
8.75% Notes due 2010	**1,350**	1,350
8.5% Notes due 2005	**1,150**	1,150
8.49% Notes due 2023	**—**	250
8.25% Mortgage Bonds due 2003	**—**	150
8.125% Notes due 2030	**600**	600
8% Junior Subordinated Debentures due 2037	**361**	—
7.92% Notes due 2023	**—**	250
7.9% Notes due 2047	**100**	100
7.8% Notes due 2027	**300**	300
7.68% Notes due 2012	**59**	64
7.625% Notes due 2006	**240**	240
7.25% Notes due 2007	**200**	200
7.25% Notes due 2031	**500**	500
7.20% Notes due 2023	**—**	250
7.125% Debentures due 2028	**300**	300
7% Debentures due 2029	**200**	200
6.95% Notes due 2029	**1,900**	1,900
6.65% Notes due 2003	**—**	100
6.65% Debentures due 2018	**300**	300
6.375% Notes due 2009	**300**	300
6.35% Notes due 2009	**750**	750
6.35% Notes due 2011	**1,750**	1,750
5.90% Notes due 2004	**1,350**	1,350
5.90% Notes due 2032	**600**	600
5.847% Notes due 2006	**126**	—
5.45% Notes due 2006	**1,250**	1,250
4.75% Notes due 2012	**1,000**	1,000
3.625% Notes due 2007	**400**	400
Commercial paper and revolving debt due to banks and others through 2008 at 1.05% – 1.08% at year-end 2003 and 1.46% – 1.94% at year-end 2002	**709**	1,517
SRW Cogeneration Limited Partnership	**—**	180
Floating Rate Notes due 2003	**—**	500
Industrial Development bonds at 1.1% – 6.1% at year-end 2003 and 1.55% – 3% at year-end 2002	**256**	153
Guarantee of savings plan bank loan payable at 1.4375% at year-end 2003	**275**	299
Note payable to Merey Sweeny, L.P. at 7%	**131**	131
Marine Terminal Revenue Refunding Bonds at 2.0% at year-end 2003	**265**	265
Other notes payable	**52**	68
Debt at face value	**17,124**	19,067
Capitalized leases	**60**	23
Net unamortized premium and discounts	**596**	676
Total debt	**17,780**	19,766
Notes payable and long-term debt due within one year	**(1,440)**	(849)
Long-term debt	**$16,340**	18,917

Maturities inclusive of net unamortized premiums and discounts in 2004 through 2008 are: $1,440 million (included in current liabilities), $1,237 million, $1,885 million, $653 million and $587 million, respectively.

Effective October 14, 2003, we entered into two new revolving credit facilities, replacing a $2 billion 364-day facility that expired on that same date. The new revolving credit facilities are a $1.5 billion 364-day facility and a $500 million five-year facility. In addition, we have two revolving credit facilities totaling $2 billion expiring in October 2006. In total, at December 31, 2003, we had four bank credit facilities in place, totaling $4 billion, available for use either as direct bank borrowings or as support for the issuance of up to $4 billion in commercial paper, a portion of which may be denominated in other currencies (limited to euro 3 billion equivalent). At December 31, 2003, we had no debt outstanding under these credit facilities, but had $709 million in commercial paper outstanding. The commercial paper is supported 100 percent by the credit facilities and the amount approximates fair value.

At December 31, 2003, $984 million of short-term obligations were classified as non-current, based on management's intent to refinance the obligations on a long-term basis through the use of existing facilities.

One of our Norwegian subsidiaries has two $300 million revolving credit facilities expiring in June 2004, under which no borrowings were outstanding at December 31, 2003.

Depending on the credit facility, borrowings may bear interest at a margin above rates offered by certain designated banks in the London interbank market or at margins above certificate of deposit 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 the third quarter of 2003, the adoption of FIN 46 for VIEs involving synthetic leases and certain other financing structures, was made and retroactively applied to January 1, 2003. The application of FIN 46 increased our balance sheet debt by approximately $2.8 billion. See Note 2 — Changes in Accounting Principles for additional information about FIN 46. With the adoption of FIN 46:

- The Phillips 66 Capital Trust II (Trust) is no longer consolidated, which removed $350 million of mandatorily redeemable preferred securities from the consolidated balance sheet and added to long-term debt $361 million of 8% Junior Subordinated Deferrable Interest Debentures due 2037. Previously this debt was eliminated in consolidation; and
- VIEs involving synthetic leases and certain other financing structures in which we are the primary beneficiary were consolidated retroactively as of January 1, 2003, which increased consolidated debt approximately $2.4 billion. Of this $2.4 billion, approximately $1.5 billion was associated with approximately 1,000 retail store sites, the majority of which we have sold or plan to sell, and two office buildings that also are part of our divestiture plan.

The $2.4 billion in debt at January 1, 2003, was comprised of the following:

- — $90 million Tosco Trust 2000-E 8.78% Senior Secured Notes due 2010;
- — $245 million Tosco Trust 2000-E 8.58% Senior Secured Notes due 2010;
- — $199 million Arctic Funding, Limited Partnership 6.85% Senior Secured Note due 2011;
- — $100 million of floating rate aviation equipment lease obligations having a final maturity in 2004;
- — $489 million of various fixed and floating rate ocean vessel lease obligations having final maturities from 2004 to 2005;
- — $1,130 million of floating rate marketing lease obligations having final maturities from 2003 to 2006; and
- — $160 million of refining equipment lease obligations at 5.847% having a final maturity in 2006.

During 2003, we reduced our commercial paper balance outstanding from $1.5 billion at December 31, 2002, to $709 million at December 31, 2003. In 2003, we paid off the following notes and debt facilities as they were called or matured and funded the payments with cash from operating activities and proceeds from asset dispositions:

- $250 million 8.49% Notes due 2023, at 104.245 percent;
- $150 million 8.25% Mortgage Bonds due May 15, 2003;
- $250 million 7.92% Notes due in 2023, at 103.96 percent;
- $250 million 7.20% Notes due 2023, at 103.60 percent;
- $100 million 6.65% Notes that matured on March 1, 2003;
- $180 million SRW Cogeneration Limited Partnership note;
- $500 million Floating Rate Notes due April 15, 2003;
- $90 million Tosco Trust 2000-E 8.78% Senior Secured Notes due 2010;
- $245 million Tosco Trust 2000-E 8.58% Senior Secured Notes due 2010;
- $199 million Arctic Funding, Limited Partnership 6.85% Senior Secured Note due 2011;
- $100 million of floating rate aviation equipment lease obligations having a final maturity in 2004;
- $489 million of fixed and floating rate ocean vessel lease obligations having final maturities from 2004 to 2005; and
- $1,130 million of floating rate marketing lease obligations having maturities from 2003 to 2006.

Also, in October and November 2003, we executed certain interest rate swaps that had the effect of converting $1.5 billion of debt from fixed to floating rate. The swaps were placed on $400 million of 3.625% Notes due 2007, $750 million of 6.35% Notes due 2009, and $350 million of 4.75% Notes due 2012. The weighted average floating rate in effect on these notes at December 31, 2003, was 2.26 percent, based on LIBOR. These swaps qualify for hedge accounting under SFAS 133, "Accounting for Derivative Instruments and Hedging Activities."

At December 31, 2003, $275 million was outstanding under the ConocoPhillips Savings Plan term loan, which will require repayment in annual installments beginning in 2009 and continuing through 2015. Under this bank loan, any participating bank in the syndicate of lenders may cease to participate on December 5, 2004, by giving not less than 180 days' prior notice to the ConocoPhillips Savings Plan and the company. One participating lender has given cessation notice. This note is classified as non-current, based on management's intent to resyndicate the loan or alternatively to refinance the note on a long-term basis, through the use of existing facilities.

Each bank participating in the ConocoPhillips Savings Plan loan has the optional right, if our current directors or their approved successors cease to be a majority of the Board, and upon not less than 90 days' notice, to cease to participate in the loan. Under the above conditions, we are required to purchase such bank's rights and obligations under the loan agreement if they are not transferred to another bank of our choice. See Note 22 — Employee Benefit Plan, for additional discussion of the ConocoPhillips Savings Plan.

Note 15 — Sales of Receivables

At December 31, 2002, certain credit card and trade receivables had been sold to two Qualifying Special Purpose Entities (QSPEs) in revolving-period securitization arrangements. These arrangements provided for us to sell, and the QSPEs to purchase, certain receivables and for the QSPEs to then issue beneficial interests of up to $1.5 billion to five bank-sponsored entities. All five bank-sponsored entities are multi-seller conduits with access to the commercial paper market and purchase interests in similar receivables from numerous other companies unrelated to us. We have no ownership interests, nor any variable interests, in any of the bank-sponsored entities. As a result, we do not consolidate any of these entities. Furthermore, we do not consolidate the QSPEs because they meet the requirements of SFAS No. 140, "Accounting for Transfers and Servicing of Financial Assets and Extinguishments of Liabilities," to be excluded from the consolidated financial statements of ConocoPhillips.

During 2003, we purchased from the bank-sponsored entities the senior interests of one of our two existing QSPEs and discontinued selling receivables to it. We have consolidated this QSPE since acquiring the senior interests. Also during 2003, the third-party beneficial interest holders approved amendments to the other QSPE to increase the amount of third-party beneficial interests that can be issued to $1.2 billion. These changes resulted in a net reduction of the maximum level of senior beneficial interests that can be issued to third-party beneficial interest holders from $1.5 billion to $1.2 billion. At December 31, 2003 and 2002, we had sold accounts receivable of $1.2 billion and $1.3 billion, respectively. The receivables transferred to the QSPE meets the isolation requirements and other requirements of SFAS No. 140 to be accounted for as sales. Accordingly, receivables transferred to the QSPEs were accounted for as sales.

We retain beneficial interests in the QSPE that are subordinate to the beneficial interests issued to the bank-sponsored entities. These retained interests, which are reported on the balance sheet in accounts and notes receivable — related parties, were $1.3 billion at both December 31, 2003 and 2002. We also retain servicing responsibility related to the sold receivables, which gives us certain benefits, the fair value of which approximates the fair value of the liability incurred for continuing to service the receivables. The carrying value of the subordinated beneficial interests approximates fair market value due to the short term of the underlying assets, which makes stress testing unnecessary.

Total cash flows received from and paid under the securitization arrangements were as follows:

	Millions of Dollars	
	2003	2002
Receivables sold at beginning of year	**$ 1,323**	940
Conoco receivables sold at August 30, 2002	—	400
New receivables sold	**25,201**	19,943*
Cash collections remitted	**(25,324)**	(19,960)*
Receivables sold at end of year	**$ 1,200**	1,323
Discounts and other fees paid on revolving balances	**$ 19**	21

**New receivables sold and cash collections remitted under these ongoing revolving securitization arrangements have been revised due to correction of disclosure calculations.*

At December 31, 2003 and 2002, we also had sold $226 million and $264 million of receivables under factoring arrangements. We retain servicing responsibility related to these sold receivables, which gives us certain benefits, the fair value of which approximates the fair value of the liability incurred for continuing to service the receivables.

Note 16 — Guarantees

At December 31, 2003, we were liable for certain contingent obligations under various contractual arrangements as described below. We are required to recognize a liability at inception for the fair value of our obligation as a guarantor for guarantees issued or modified after December 31, 2002. Unless the carrying amount of the liability is noted, 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

- We have a construction completion guarantee related to debt and bond financing arrangements secured by the Merey Sweeny, L.P. (MSLP) joint-venture project in Texas. The maximum potential amount of future payment under the guarantee, including joint-and-several debt at its gross amount, is estimated to be $400 million assuming that completion certification is not achieved. Of this amount, $200 million is attributable to Petroleos de Venezuela, S.A. (PDVSA), because they are joint-and-severally liable for a portion of the debt. If completion certification is not attained by June 18, 2004, the full debt balance could be called. MSLP is currently awaiting receipt of a permit for a new waste water pipeline and working to resolve issues in placing its insurance program, after which we expect to achieve completion certification in the second quarter of 2004. The debt is non-recourse to us upon completion certification.
- We also issued a construction completion guarantee related to debt financing arrangements for the Hamaca Holding LLC joint-venture project in Venezuela. The maximum potential amount of future payments under the guarantee is estimated to be $440 million, which could be payable if the full debt financing capacity is utilized and startup and completion of the Hamaca project is not achieved by October 1, 2005. The project financing debt will become non-recourse upon startup and completion certification.

Guarantees of Joint-Venture Debt

- At December 31, 2003, we had guarantees of approximately $340 million outstanding for our portion of joint-venture debt obligations, which have terms of up to 22 years. Included in these outstanding guarantees was $156 million associated with the Polar Lights Company joint venture in Russia. Payment will be required if a joint venture defaults on its debt obligations.

Other Guarantees

- In addition to the construction completion guarantee explained above, the MSLP agreement also requires the partners in the venture to pay cash calls as required to meet the minimum operating requirements of the venture, in the event revenues do not cover expenses over the next 20 years. Our maximum potential future payments under the agreement are estimated to be $300 million, assuming MSLP does not earn any revenue over the entire period and fixed costs cannot be reduced. To the extent revenue is generated by the venture or fixed costs are reduced, future required payments would be reduced accordingly.
- In February 2003, we entered into two agreements establishing separate guarantee facilities of $50 million each for two liquefied natural gas ships that were then under construction. 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 an aggregate of $100 million. Actual gross payments over the 20 years could exceed that amount to the extent cash is received by us. 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. In February 2003, based on the then current market view of both long-term and short-term shipping capacity, rates, and utilization probability, we estimated the fair value of the liability under these guarantee facilities to be immaterial. In September 2003, the first ship was delivered to its owner and the second ship is scheduled for delivery to its owner in 2005. With respect to the first ship, the amount drawn under the guarantee facility at December 31, 2003, was less than $1 million.
- We have other guarantees totaling approximately $190 million, which consist primarily of dealer and jobber loan guarantees to support our marketing business, a guarantee supporting a lease assignment on a corporate aircraft, a guarantee associated with a pending lawsuit and guarantees of lease payment obligations for a joint venture. The carrying amount recorded for these other guarantees as of December 31, 2003, was $13 million. These guarantees generally extend up to 15 years and payment would only be required if the dealer, jobber or lessee goes into default, or if an adverse decision occurs in the lawsuit.

Indemnifications

- Over the years, we have entered into various agreements to sell ownership interests in certain corporations and joint ventures. In addition, we entered into a Tax Sharing Agreement in 1998 related to Conoco's separation from DuPont. These agreements typically include indemnifications for additional taxes determined to be due under the relevant tax law, in connection with operations for years prior to the sale or separation. Generally, the obligation extends until the related tax years are closed. The maximum potential amount of future payments under the indemnifications is the amount of additional tax determined to be due under relevant tax law and the various agreements. There are no material outstanding claims that have been asserted under these agreements.
- During 2003, we sold several assets, including FTC-mandated sales of downstream and midstream assets, certain exploration and production assets, and downstream retail and wholesale sites, giving rise to qualifying indemnifications. Agreements associated with these sales include indemnifications for taxes, environmental liabilities, underground storage tank repairs or replacements, permits and licenses, employee claims, real estate indemnity against tenant defaults, and litigation. The

term of these indemnifications is generally indefinite and the maximum amount of future payments is generally unlimited. The carrying amount recorded for these indemnifications as of December 31, 2003, is $221 million. Although it is reasonably possible that 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 are $81 million of environmental accruals for known contamination that is included in asset retirement obligations and accrued environmental costs at December 31, 2003. For additional information about environmental liabilities, see Note 13 — Asset Retirement Obligations and Accrued Environmental Costs, and Note 17 — Contingencies.

- As part of our normal ongoing business operations and consistent with industry practice, we enter into numerous agreements with other parties, which apportion future risks among the parties to the transaction or relationship governed by the agreements. One method of apportioning risk is the inclusion of provisions requiring one party to indemnify the other against losses that might otherwise be incurred by the other party in the future. Many of our agreements contain an indemnity or indemnities that require us to perform certain acts, such as remediation, as a result of the occurrence of a triggering event or condition. In some instances we indemnify third parties against losses resulting from certain events or conditions that arise out of the operations of our equity affiliates.

The nature of these numerous indemnity obligations are diverse and each has different terms, business purposes, and triggering events or conditions. Consistent with customary business practice, any particular indemnity obligation incurred is the result of a negotiated transaction or contractual relationship for which we have accepted a certain level of risk in return for a financial or other type of benefit. In addition, the indemnities in each agreement vary widely in their definitions of both triggering events and the resulting obligations contingent on those triggering events.

With regard to indemnifications, our risk management philosophy is to limit risk in any transaction or relationship to the maximum extent reasonable in relation to commercial and other considerations. Before accepting any indemnity obligation, we make an informed risk management decision considering, among other things, the remoteness of the possibility that the triggering event will occur, the potential costs to perform under any resulting indemnity obligation, possible actions to reduce the likelihood of a triggering event or to reduce the costs of performing under the indemnity obligation, whether we are indemnified by an unrelated third party, insurance coverage that may be available to offset the cost of the indemnity obligation, and the benefits from the transaction or relationship.

Because many of our indemnity obligations are not limited in duration or potential monetary exposure, we cannot calculate a reasonable estimate of the maximum potential amount of future payments that could be paid under our indemnity obligations stemming from all our existing agreements. The carrying amount recorded for these indemnifications as of December 31, 2003, was $224 million, which is for known contamination and is included in asset retirement obligations and accrued environmental costs. For additional information about environmental liabilities and contingencies, see Note 13 — Asset Retirement Obligations and Accrued Environmental Costs, and Note 17 — Contingencies.

Note 17 — Contingencies

We are subject to various lawsuits and claims including, but not limited to: actions challenging oil and gas royalty and severance tax payments; actions related to gas measurement and valuation methods; actions related to joint interest billings to operating agreement partners; and claims for damages resulting from leaking underground storage tanks, or other accidental releases, with related toxic tort claims. As a result of Conoco's separation agreement with DuPont, we also have assumed responsibility for current and future claims related to certain discontinued chemicals and agricultural chemicals businesses operated by Conoco in the past. In general, the effect on future financial results is not subject to reasonable estimation because considerable uncertainty exists. The ultimate liabilities resulting from such lawsuits and claims may be material to results of operations in the period in which they are recognized.

In the case of all known contingencies, we accrue a liability when the loss is probable and the amount is reasonably estimable. 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. Based on currently available information, we believe that it is remote that future costs related to known contingent liability exposures will exceed current accruals by an amount that would have a material adverse impact on our financial statements.

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 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 consideration the likely effects of societal and economic factors. 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', 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 assumed in a purchase business combination, which we record such costs 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 13 — Asset Retirement Obligations and Accrued Environmental Costs for a summary of our accrued environmental liabilities.

Other Legal Proceedings — We are a party to a number of other legal proceedings pending in various courts or agencies for which, in some instances, no provision has been made.

Other Contingencies — We have contingent liabilities resulting from throughput agreements with pipeline and processing companies. 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 by us. In addition, we have various purchase commitments for materials, supplies, services and items of permanent investment incident to the ordinary conduct of business.

Note 18 — 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 Executive Vice President of Commercial monitors commodity price risk. Both report to the Chief Executive Officer. The Commercial Group 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 (Statement No. 133 or 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, 2003, were $340 million and $268 million, respectively, and appear as accounts and notes receivables, other assets, accounts payable, or other liabilities and deferred credits on the balance sheet.

The accounting for changes in fair value (i.e., gains or losses) of a derivative instrument depends on whether it meets the qualifications for, and has been designated as, a SFAS No. 133 hedge, and the type of hedge. At this time, we are not using SFAS No. 133 hedge accounting for commodity derivative contracts, but we are using hedge accounting for the interest-rate derivatives noted below. All gains and losses, realized or unrealized, from derivative contracts not designated as SFAS No. 133 hedges have been recognized in the 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, which either have been designated normal purchase/ normal sales, or do not meet the SFAS No. 133 definition of a derivative.

Interest Rate Derivative Contracts — During the fourth quarter of 2003, we executed interest rate swaps that had the effect of converting $1.5 billion of debt from fixed to floating rates. These swaps qualified for and have been designated as fair-value hedges using the short-cut method of hedge accounting provided by SFAS No. 133, which permits the assumption that changes in the value of the derivative perfectly offset changes in the value of the debt; therefore, no gain or loss is recognized due to hedge ineffectiveness.

Currency Exchange Rate Derivative Contracts — We have foreign currency exchange rate risk resulting from operations in over 40 countries. 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. Hedge accounting is not currently being used for any of our foreign currency derivatives.

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 market prices of commodity purchases and sales; 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 group 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; and
- 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 12 months ended December 31, 2003, 2002 and 2001, the gains or losses from this activity were not material to our cash flows or income from continuing operations.

At December 31, 2003, we were not using hedge accounting for any commodity derivative contracts.

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, which are placed in high-quality money market funds and time deposits with major international banks and financial institutions, are generally not maintained at levels material to our financial position. 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 International Petroleum Exchange of London Limited.

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.
- Debt and mandatorily redeemable preferred securities: The carrying amount of our floating-rate debt approximates fair value. The fair value of the fixed-rate debt and mandatorily redeemable preferred securities is estimated based on quoted market prices.
- 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 International Petroleum Exchange of London Limited, 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 financial instruments at December 31 were:

	Millions of Dollars			
	Carrying Amount		Fair Value	
	2003	2002	**2003**	2002
Financial assets				
Foreign currency derivatives	$ **44**	17	**44**	17
Interest rate derivatives	**13**	—	**13**	—
Commodity derivatives	**283**	180	**283**	180
Financial liabilities				
Total debt, excluding capital leases	**17,720**	19,743	**18,905**	20,844
Mandatorily redeemable other minority interests and preferred securities	**141**	491	**142**	516
Interest rate derivatives	**13**	22	**13**	22
Foreign currency derivatives	**5**	4	**5**	4
Commodity derivatives	**250**	180	**250**	180

Note 19 — Preferred Stock and Other Minority Interests

Company-Obligated Mandatorily Redeemable Preferred Securities of Phillips 66 Capital Trusts

During 1996 and 1997, we formed two statutory business trusts, Phillips 66 Capital I (Trust I) and Phillips 66 Capital II (Trust II), with ConocoPhillips owning all the common stock. The trusts were created for the sole purpose of issuing securities and investing the proceeds thereof in an equivalent amount of our subordinated debt securities. We established the trusts to raise funds for general corporate purposes.

On May 31, 2002, we redeemed all of our outstanding 8.24% Junior Subordinated Deferrable Interest Debentures due 2036 held by Trust I. This triggered the redemption of $300 million of Trust I's 8.24% Trust Originated Preferred Securities at par value, $25 per share. A loss of $8 million before-tax, $6 million after-tax, was incurred during the second quarter of 2002 as a result of the redemption.

Trust II has outstanding $350 million of 8% Capital Securities (Capital Securities). The sole asset of Trust II is $361 million of the company's 8% Junior Subordinated Deferrable Interest Debentures due 2037 (Subordinated Debt Securities II) purchased by Trust II on January 17, 1997. The Subordinated Debt Securities II are due January 15, 2037, and are redeemable in whole, or in part, at our option on or after January 15, 2007, at 103.94 percent declining annually until January 15, 2017, when they can be called at par, or $1,000 per share, plus accrued and unpaid interest. When we redeem the Subordinated Debt Securities II, Trust II is required to apply all redemption proceeds to the immediate redemption of the Capital Securities. We fully and unconditionally guarantee Trust II's obligations under the Capital Securities.

Subordinated Debt Securities II are unsecured obligations of ours that are subordinate and junior in right of payment to all our present and future senior indebtedness.

Effective January 1, 2003, with the adoption of FIN 46, Trust II was deconsolidated because we are not the primary beneficiary. Application of FIN 46 required deconsolidation of Trust II, which had the effect of increasing debt by $361 million since the Subordinated Debt Securities II were no longer eliminated in consolidation, and eliminating the $350 million of mandatorily redeemable preferred securities. Prior to the adoption of FIN 46, the subordinated debt securities and related income statement effects were eliminated in the company's consolidated financial statements. See Note 2 — Changes in Accounting Principles for additional information.

Other Minority Interests

The minority limited partner in Conoco Corporate Holdings L.P., a limited-life entity that must be liquidated in 2019, is entitled to a cumulative annual 7.86 percent priority return on its investment. The net minority interest in Conoco Corporate Holdings held by the limited partner was $141 million at December 31, 2003 and 2002, and is callable without penalty beginning in the fourth quarter of 2004.

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 1.27 percent. The preferred return at December 31, 2003 and 2002, was 2.48 percent and 2.70 percent, respectively. At December 31, 2003 and 2002, the minority interest was $496 million and $504 million, respectively.

Ashford Energy Capital S.A. continues to be consolidated in our financial statements under the provisions of FIN 46 because we are the primary beneficiary. See Note 2 — Changes in Accounting Principles for additional information.

The remaining minority interest amounts relate to consolidated operating joint ventures that have minority interest owners. The largest amount relates to the Bayu-Undan project. See Note 7 — Subsidiary Equity Transactions.

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, 2003.

Note 20 — Preferred Share Purchase Rights

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, 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. In addition, the rights enable holders to either acquire additional shares of ConocoPhillips common stock or 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 21 — 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 on us imposed 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, 2003, future minimum rental payments due under non-cancelable leases, including those associated with discontinued operations, were:

	Millions of Dollars
2004	$ 471
2005	434
2006	376
2007	328
2008	291
Remaining years	1,173
Total	3,073
Less income from subleases	419*
Net minimum operating lease payments	$2,654

**Includes $182 million related to railroad cars subleased to CPChem, a related party.*

We have agreements with a shipping company for the long-term charter of two crude oil tankers that are currently under construction. The charters will be accounted for as operating leases upon delivery, which is expected in the first quarter of 2004. Upon delivery, the base term of the charter agreements is 12 years, with certain renewal options by ConocoPhillips. The total operating lease commitment over the 12-year term for the two tankers would be $87 million on an estimated bareboat basis.

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

	Millions of Dollars		
	2003	2002	2001
Total rentals*	**$448**	541	271
Less sublease rentals	**24**	21	22
	$424	520	249

**Includes $31 million and $12 million of contingent rentals in 2003 and 2002, respectively. Contingent rentals primarily are related to retail sites and refining equipment, and are based on volume of product sold or throughput. Contingent rentals in 2001 were not significant.*

Note 22 — 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	
	2003		2002		**2003**	2002
	U.S.	**Int'l.**	U.S.	Int'l.		
Change in Benefit Obligation						
Benefit obligation at January 1	**$3,079**	**1,501**	1,432	417	**919**	239
Service cost	**131**	**61**	75	32	**17**	9
Interest cost	**197**	**89**	133	48	**61**	31
Plan participant contributions	**—**	**1**	—	2	**27**	15
Plan amendments	**—**	**54**	(12)	—	**—**	133
Actuarial (gain) loss	**187**	**268**	205	(21)	**46**	31
Acquisitions	**—**	**—**	1,349	908	**—**	509
Benefits paid	**(571)**	**(60)**	(159)	(23)	**(72)**	(47)
Curtailment	**(3)**	**(5)**	(36)	—	**—**	(4)
Recognition of termination benefits	**—**	**9**	92	3	**—**	3
Foreign currency exchange rate change	**—**	**157**	—	135	**6**	—
Benefit obligation at December 31	**$3,020**	**2,075**	3,079	1,501	**1,004**	919
Accumulated benefit obligation portion of above at December 31	**$2,379**	**1,764**	2,455	1,325		
Change in Fair Value of Plan Assets						
Fair value of plan assets at January 1	**$1,233**	**1,027**	732	381	**11**	21
Actual return on plan assets	**228**	**133**	(85)	(74)	**2**	(5)
Acquisitions	**—**	**—**	600	594	**—**	—
Company contributions	**570**	**91**	145	39	**39**	27
Plan participant contributions	**—**	**1**	—	2	**27**	15
Benefits paid	**(571)**	**(60)**	(159)	(21)	**(72)**	(47)
Foreign currency exchange rate change	**—**	**111**	—	106	**—**	—
Fair value of plan assets at December 31	**$1,460**	1,303	1,233	1,027	**7**	11
Funded Status						
Excess obligation	**$(1,560)**	**(772)**	(1,846)	(474)	**(997)**	(908)
Unrecognized net actuarial loss	**554**	**369**	697	171	**100**	60
Unrecognized prior service cost	**26**	**53**	30	5	**111**	131
Total recognized amount in the consolidated balance sheet	**$ (980)**	**(350)**	(1,119)	(298)	**(786)**	(717)
Components of above amount:						
Prepaid benefit cost	**$ —**	**73**	—	52	**—**	—
Accrued benefit liability	**(999)**	**(538)**	(1,484)	(400)	**(786)**	(717)
Intangible asset	**5**	**40**	43	3	**—**	—
Accumulated other comprehensive loss	**14**	**75**	322	47	**—**	—
Total recognized	**$ (980)**	**(350)**	(1,119)	(298)	**(786)**	(717)
Weighted-Average Assumptions Used to Determine Benefit Obligations at December 31						
Discount rate	**6.00%**	**5.45**	6.75	5.85	**6.00**	6.75
Rate of compensation increase	**4.00**	**3.55**	4.00	3.80	**4.00**	4.00
Weighted-Average Assumptions Used to Determine Net Periodic Benefit Cost for years ended December 31						
Discount rate	**6.75%**	**5.85**	7.25	6.30	**6.75**	7.25
Expected return on plan assets	**7.05**	**7.45**	8.70	7.60	**5.50**	5.20
Rate of compensation increase	**4.00**	**3.80**	4.00	3.75	**4.00**	4.00

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.

We use a December 31 measurement date for the majority of our plans.

During 2003, we recorded a benefit to other comprehensive income related to minimum pension liability adjustments totaling $280 million ($175 million net of tax), resulting in accumulated other comprehensive loss due to minimum pension liability adjustments at December 31, 2003, of $89 million ($61 million net of tax). During 2002, we recorded charges to other comprehensive loss totaling $149 million ($93 million net of tax), resulting in accumulated other comprehensive loss due to minimum pension liability adjustments at December 31, 2002, of $369 million ($236 million net of tax).

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 $4,489 million, $3,661 million, and $2,415 million at December 31, 2003, respectively, and $4,288 million, $3,542 million, and $2,259 million at December 31, 2002, respectively.

For our unfunded non-qualified supplemental key employee pension plans, the projected benefit obligation and the accumulated benefit obligation were $237 million and $177 million, respectively, at December 31, 2003, and were $260 million and $206 million, respectively, at December 31, 2002.

	Millions of Dollars								
	Pension Benefits						Other Benefits		
	2003		2002		2001		**2003**	2002	2001
	U.S.	**Int'l.**	U.S.	Int'l.	U.S.	Int'l.			
Components of Net Periodic Benefit Cost									
Service cost	**$131**	**61**	75	32	40	15	**17**	9	4
Interest cost	**197**	**89**	133	48	82	24	**61**	31	11
Expected return on plan assets	**(90)**	**(78)**	(73)	(49)	(74)	(30)	**—**	(1)	(1)
Amortization of prior service cost	**4**	**5**	5	2	6	1	**19**	8	(1)
Recognized net actuarial loss	**70**	**17**	48	7	16	—	**6**	3	2
Amortization of net asset	**—**	**—**	—	—	—	(1)	**—**	—	—
Net periodic benefit cost	**$312**	**94**	188	40	70	9	**103**	50	15

As a result of the ConocoPhillips merger, we recognized settlement losses of $120 million and special termination benefits of $9 million in 2003, and we recorded curtailment losses of $23 million and special termination benefits of $98 million in 2002. During 2001, we recorded a curtailment gain of $2 million and settlement losses of $10 million.

In determining net pension and other postretirement benefit costs, we have elected to amortize net gains and losses on a straight-line basis over 10 years. Prior service cost is amortized on a straight-line basis over the average remaining service period of employees expected to receive benefits under the plan.

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 participants not subject to the cap is assumed to decrease gradually from 10 percent in 2004 to 5.5 percent in 2015.

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 2003 amounts:

	Millions of Dollars	
	One-Percentage-Point	
	Increase	Decrease
Effect on total of service and interest cost components	$ 1	(1)
Effect on the postretirement benefit obligation	18	(14)

In December 2003, President Bush signed into law the Medicare Prescription Drug, Improvement and Modernization Act of 2003 (the Act). The Act expanded Medicare to include, for the first time, coverage for prescription drugs. We sponsor retiree medical programs for most groups of employees in the United States, and we expect that this legislation will eventually reduce our costs for some of these programs. At this point, our investigation into our response to the legislation is preliminary, as we await guidance from various governmental and regulatory agencies concerning the requirements that must be met to obtain these cost reductions, as well as the manner in which such savings should be measured. Because of various uncertainties related to our response to this legislation and the appropriate accounting methodology for this event, we have elected to defer financial recognition of this legislation until the FASB issues final accounting guidance. When issued, that final guidance could require us to change previously reported information. This deferral is permitted under FASB Staff Position No. FAS 106-1, "Accounting and Disclosure Requirements Related to the Medicare Prescription Drug, Improvement and Modernization Act of 2003."

Plan Assets

The company follows 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. Any use of leverage is prohibited. At December 31, 2003, there were no shares of company stock included in plan assets, compared with 4,300 shares at year-end 2002. 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 2004, we expect to contribute approximately $400 million to our domestic qualified and non-qualified benefit plans and $100 million to our international qualified and non-qualified benefit plans.

Weighted-average asset allocations at December 31 by asset category are as follows:

	Pension			
	U.S.		International	
	2003	2002	**2003**	2002
Asset Category				
Equity securities	**62%**	55	**48**	48
Debt securities	**22**	24	**46**	47
Participating interest in annuity contract	**12**	16	**—**	—
Real estate	**1**	2	**1**	1
Other	**3**	3	**5**	4
	100%	100	**100**	100

The above asset allocations are all within guidelines established by the plan fiduciaries.

A portion of the U.S. pension plan assets are 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, and was valued at \$169 million and \$198 million at December 31, 2003, and December 31, 2002, respectively. At both December 31, 2003, and December 31, 2002, the participating interest consisted of 62 percent debt securities and 38 percent equity securities. 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.

Weighted-average target asset allocations by asset category are as follows:

	Pension	
	U.S.	International
Asset Category		
Equity securities	57%	52
Debt securities	24	46
Participating interest in annuity contract	12	—
Real estate	5	1
Other	2	1
	100%	100

Defined Contribution Plans

Prior to the close of business on December 31, 2002, most U.S. employees (excluding retail service station employees) were eligible to participate in either the company-sponsored Thrift Plan of Phillips Petroleum Company, the Long-Term Stock Savings Plan of Phillips Petroleum Company, the Tosco Corporation Capital Accumulation Plan, and/or the Thrift Plan for Employees of Conoco Inc. The new ConocoPhillips Savings Plan (CPSP) was created at the close of business on December 31, 2002, with the merger of the Thrift Plan of Phillips Petroleum Company into the Long-Term Stock Savings Plan of Phillips Petroleum Company. The Thrift Plan of Phillips Petroleum Company became the thrift feature of the CPSP, and the Long-Term Stock Savings Plan became the stock savings feature. On the same date, most of the accounts in the Tosco Corporation Capital Accumulation Plan were transferred into the CPSP. On October 3, 2003, the assets of the Thrift Plan for Employees of Conoco Inc. were merged into the CPSP, resulting in the CPSP becoming the primary defined contribution plan for ConocoPhillips.

At December 31, 2003, employees could deposit up to 30 percent of their pay in the thrift feature of the CPSP to a choice of 31 investment funds. ConocoPhillips matched \$1 for each \$1 deposited, up to 1.25 percent of pay. Company contributions charged to expense for the CPSP and the predecessor plans, excluding the stock savings feature (discussed below), were \$19 million in 2003, \$40 million in 2002, and \$14 million in 2001.

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 2004 through 2008, 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 \$76 million, \$39 million and \$33 million in 2003, 2002 and 2001, respectively, all of which was compensation expense. In 2003, 2002 and 2001, respectively, we made cash contributions to the CPSP of \$0.2 million, \$2 million and \$17 million. In 2003, 2002 and 2001, we contributed 1,483,780 shares, 771,479 shares and 292,857 shares, respectively, of company common stock from the Compensation and Benefits Trust. The shares had a fair market value of \$80 million, \$41 million and \$17 million, respectively. Dividends used to service debt were \$28 million each in 2003, 2002 and 2001.

These dividends reduced the amount of expense recognized each period. Interest incurred on the CPSP debt in 2003, 2002 and 2001 was \$5 million, \$7 million and \$17 million, respectively.

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

	2003	2002
Unallocated shares	**7,077,880**	7,717,710
Allocated shares	**10,312,220**	14,925,443
Total shares	**17,390,100**	22,643,153

The fair value of unallocated shares at December 31, 2003, and 2002, was \$464 million and \$373 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 $20 million in 2003, and was not significant in 2002 and 2001 because the majority of these plans were acquired in the merger.

Stock-Based Compensation Plans

Under the Phillips Omnibus Securities Plan approved by shareholders in 1993, stock options and stock awards for certain employees were authorized for up to eight-tenths of 1 percent (0.8 percent) of the total outstanding shares as of December 31 of the year preceding the awards. Any shares not issued in the current year were available for future grant. Upon the adoption of the Phillips 2002 Omnibus Securities Plan discussed below, the number of shares available for issuance under the Phillips Omnibus Securities Plan was limited to 700,000. The term of the Phillips Omnibus Securities Plan ended on December 31, 2002.

In 2001, shareholders approved the Phillips 2002 Omnibus Securities Plan, which has a term of five years, from January 1, 2002, through December 31, 2006, and which is authorized to issue approximately 18,000,000 shares of company common stock. The two plans also provided for non-stock-based awards.

Shares of company stock to employees were:

	2003	2002	2001
Shares	**260,677**	1,090,082	237,849
Weighted-average fair value	**$48.75**	57.84	56.23

Stock options granted under provisions of the plans 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 normally become exercisable in increments of up to one-third on each anniversary date following the date of grant. Stock Appreciation Rights (SARs) may, from time to time, be affixed to the options. Options exercised in the form of SARs permit the holder to receive stock, or a combination of cash and stock, subject to a declining cap on the exercise price.

The merger was a change-in-control event that resulted in a lapsing of restrictions on, and payout of, stock and stock option awards under the plans. We offered to exchange certain stock awards under the plans with new awards in the form of restricted stock units. These new restricted stock units were converted, at the time of the merger, into awards based on the same number of shares of our common stock.

Conoco had several stock-based compensation plans that were assumed in the merger: the 1998 Stock and Performance Incentive Plan; the 1998 Key Employee Stock Performance Plan; the 1998 Global Performance Sharing Plan; and the 2001 Global Performance Sharing Plan. Upon the merger, outstanding stock options under these plans were converted to ConocoPhillips stock options at the merger exchange ratio of 0.4677.

The Conoco plans award stock options at exercise prices equivalent to the average market price of the stock on the date the option was granted. Awards have option terms of 10 years and become exercisable based on various formulas, including those that become exercisable one year from date of grant, and those that become exercisable in increments of one-third on each anniversary date following date of grant. In total, there were 10.3 million shares of company stock at December 31, 2003, available for issuance under the Conoco plans.

In August 2002, we issued 23.3 million vested stock options to replace unexercised Conoco stock options at the time of the merger. These options had a weighted-average exercise price of $47.65 per option, and a Black-Scholes option-pricing model value of $16.50 per option. In September 2001, we issued 4.7 million vested stock options to replace unexercised Tosco stock options at the time of the acquisition. These options had a weighted-average exercise price of $23.15 per option, and a Black-Scholes option-pricing model value of $32.51 per option.

A summary of our stock option activity follows:

	Options	Weighted-Average Exercise Price
Outstanding at December 31, 2000	9,862,967	$43.82
Granted (including Tosco exchange)	9,038,571	38.81
Exercised	(2,373,062)	22.36
Forfeited	(96,126)	60.41
Outstanding at December 31, 2001	16,432,350	$44.06
Granted (including the merger)	28,830,903	48.11
Exercised	(2,032,232)	24.66
Forfeited	(124,416)	57.78
Outstanding at December 31, 2002	43,106,605	$47.65
Granted	**6,719,874**	**48.79**
Exercised	**(3,697,271)**	**31.98**
Forfeited	**(299,631)**	**50.07**
Outstanding at December 31, 2003	**45,829,577**	**$49.07**

The weighted-average fair market values of the options granted over the past three years, as calculated using the Black-Scholes option-pricing model, and the significant assumptions used to calculate these values were as follows:

	Millions of Dollars		
	2003	2002	2001
Average grant date fair value of options	**$9.95**	11.67	23.19
Assumptions used			
Risk-free interest rate	**3.4%**	4.1	4.5
Dividend yield	**3.3%**	3.0	2.5
Volatility factor	**25.9%**	26.2	27.0
Expected life (years)	**6**	6	5

Options Outstanding at December 31, 2003

		Weighted-Average	
Exercise Prices	Options	Remaining Lives	Exercise Price
$12.16 to $41.22	**7,390,364**	**2.41 years**	**$34.04**
$42.42 to $49.95	**23,070,483**	**6.64 years**	**47.38**
$50.22 to $66.72	**15,368,730**	**7.52 years**	**58.82**

Options Exercisable at December 31

	Exercise Prices	Options	Weighted-Average Exercise Price
2003	**$12.16 to $41.22**	**7,217,227**	**$34.20**
	$42.42 to $49.95	**14,322,066**	**46.83**
	$50.22 to $66.72	**12,987,973**	**59.54**
2002	$ 9.04 to $31.44	5,067,979	$25.06
	$31.52 to $44.91	6,384,431	39.88
	$45.75 to $66.72	21,614,181	52.17
2001	$ 9.04 to $31.44	3,056,009	$22.67
	$31.52 to $44.91	3,075,354	38.06
	$45.75 to $64.43	3,525,616	48.32

For information on our 2003 adoption of SFAS No. 123, see Note 1 — Accounting Policies.

Compensation and Benefits Trust (CBT)

The 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 29.2 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 2003 and 2002, shares transferred out of the CBT were 1,483,780 and 771,479, respectively. At December 31, 2003, 25.3 million shares remained in the CBT. All shares are required to be transferred out of the CBT by January 1, 2021.

Note 23 — Taxes

Taxes charged to income from continuing operations were:

	Millions of Dollars		
	2003	2002	2001
Taxes Other Than Income Taxes			
Excise	**$13,738**	6,246	2,177
Property	**290**	244	148
Production	**413**	303	328
Payroll	**149**	99	54
Environmental	**7**	5	14
Other	**82**	40	19
	$14,679	6,937	2,740
Income Taxes			
Federal			
Current	**$ 536**	64	129
Deferred	**637**	56	426
Foreign			
Current	**2,559**	1,188	842
Deferred	**(161)**	114	126
State and local			
Current	**136**	57	97
Deferred	**37**	(36)	20
	$ 3,744	1,443	1,640

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	
	2003	2002
Deferred Tax Liabilities		
Properties, plants and equipment, and intangibles	**$10,436**	10,147
Investment in joint ventures	**1,490**	1,013
Inventory	**486**	385
Other	**267**	144
Total deferred tax liabilities	**12,679**	11,689
Deferred Tax Assets		
Benefit plan accruals	**1,334**	1,304
Asset retirement obligations and accrued environmental costs	**1,584**	724
Deferred state income tax	**227**	201
Other financial accruals and deferrals	**144**	311
Alternative minimum tax carryforwards	**317**	421
Operating loss and credit carryforwards	**1,105**	650
Other	**153**	394
Total deferred tax assets	**4,864**	4,005
Less valuation allowance	**906**	608
Net deferred tax assets	**3,958**	3,397
Net deferred tax liabilities	**$ 8,721**	8,292

Current assets, long-term assets, current liabilities and long-term liabilities included deferred taxes of $-0- million, $53 million, $209 million and $8,565 million, respectively, at December 31, 2003, and $68 million, $41 million, $40 million and $8,361 million, respectively, at December 31, 2002.

We have operating loss and credit carryovers in multiple taxing jurisdictions. These attributes generally expire between 2004 and 2013 with some carryovers, including the alternative minimum tax, having indefinite carryforward periods.

Valuation allowances have been established for certain operating 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 2003, valuation allowances increased $298 million. This reflects increases of $498 million primarily related to foreign tax loss carryforwards, partially offset by decreases of $200 million, primarily related to foreign tax loss carryforwards that have expired or that have been utilized. Based on our historical taxable income, its 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.

The Conoco purchase price allocation for the merger resulted in deferred tax liabilities of $3,841 million. Additionally, there is a valuation allowance for certain deferred tax assets of $251 million, for which subsequently recognized tax benefits, if any, will be allocated to goodwill.

At December 31, 2003, and December 31, 2002, income considered to be permanently reinvested in certain foreign subsidiaries and foreign corporate joint ventures totaled approximately $2,046 million and $2,171 million, respectively. Deferred income taxes have not been provided on this income, as we do not plan to initiate any action that would require the payment of income taxes. It is not practicable to estimate the amount of additional tax that might be payable on this foreign income if distributed.

The 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		
	2003	2002	2001	**2003**	2002	2001
Income from continuing operations before income taxes						
United States	**$4,137**	605	2,066	**49.6%**	28.3	63.7
Foreign	**4,200**	1,536	1,175	**50.4**	71.7	36.3
	$8,337	2,141	3,241	**100.0%**	100.0	100.0
Federal statutory income tax	**$2,918**	749	1,134	**35.0%**	35.0	35.0
Foreign taxes in excess of federal statutory rate	**792**	680	515	**9.5**	31.8	15.9
Domestic tax credits	**(25)**	(77)	(84)	**(.3)**	(3.6)	(2.6)
Write-off of acquired in-process research and development costs	**—**	86	—	**—**	4.0	—
State income tax	**112**	14	76	**1.3**	.6	2.3
Other	**(53)**	(9)	(1)	**(.6)**	(.4)	—
	$3,744	1,443	1,640	**44.9%**	67.4	50.6

Our 2003 tax expense was reduced by $227 million as a result of tax law changes in Norway, Canada and Timor Lesté due to adjustments of net deferred tax liabilities.

Note 24 — 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
2003			
Minimum pension liability adjustment	**$ 271**	**103**	**168**
Unrealized gain on securities	**6**	**2**	**4**
Foreign currency translation adjustments	**865**	**228**	**637**
Hedging activities	**7**	**—**	**7**
Equity affiliates:			
Foreign currency translation	**149**	**—**	**149**
Derivatives related	**32**	**12**	**20**
Other comprehensive income	**$1,330**	**345**	**985**
2002			
Minimum pension liability adjustment	$ (149)	(56)	(93)
Unrealized loss on securities	(3)	—	(3)
Foreign currency translation adjustments	223	41	182
Hedging activities	(1)	—	(1)
Equity affiliates:			
Foreign currency translation	40	—	40
Derivatives related	(34)	—	(34)
Other comprehensive income	$ 76	(15)	91
2001			
Minimum pension liability adjustment	$ (220)	(77)	(143)
Unrealized loss on securities	(3)	(1)	(2)
Foreign currency translation adjustments	(14)	—	(14)
Hedging activities	(4)	—	(4)
Equity affiliates:			
Foreign currency translation	(3)	—	(3)
Derivatives related	17	6	11
Other comprehensive loss	$ (227)	(72)	(155)

See Note 22 — Employee Benefit Plans for more information on the minimum pension liability adjustment. The after-tax amount for 2003 of $168 million includes a net charge of $7 million related to a pension plan for which we are not the primary obligor, and thus is not included in the pension disclosures in Note 22 — Employee Benefit Plans. The accumulated pension liability adjustment at December 31, 2003, of $68 million also included this $7 million accumulated loss.

Unrealized gain (loss) on securities relate to available-for-sale securities held by irrevocable grantor trusts that fund certain of our domestic, non-qualified supplemental key employee pension plans.

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 essentially permanent in duration.

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

	Millions of Dollars	
	2003	2002
Minimum pension liability adjustment	**$ (68)**	(236)
Foreign currency translation adjustments	**735**	98
Unrealized gain on securities	**5**	1
Deferred net hedging gain/(loss)	**2**	(5)
Equity affiliates:		
Foreign currency translation	**150**	1
Derivatives related	**(3)**	(23)
Accumulated other comprehensive income (loss)	**$821**	(164)

Note 25 — Cash Flow Information

	Millions of Dollars		
	2003	2002	2001
Non-Cash Investing and Financing Activities			
Increase in properties, plants and equipment in exchange for related increase in asset retirement obligations associated with the initial implementation of SFAS No. 143	**$1,229**	—	—
Increase in properties, plants and equipment from incurrence of asset retirement obligations due to repeal of Norway Removal Grant Act	**336**	—	—
Increase in properties, plants and equipment related to the implementation of FIN 46	**940**	—	—
Increase in long-term debt through the implementation and continuing application of FIN 46	**2,774**	—	—
Increase in assets of discontinued operations held for sale related to implementation of FIN 46	**726**	—	—
The merger by issuance of stock	**—**	15,974	—
Acquisition of Tosco by issuance of stock	**—**	—	7,049
Investment in properties, plants and equipment of businesses through the assumption of non-cash liabilities	**—**	181	125
Cash Payments			
Interest	**$ 839**	441	324
Income taxes	**2,909**	1,363	1,504

Note 26 — Other Financial Information

	Millions of Dollars Except Per Share Amounts		
	2003	2002	2001
Interest			
Incurred			
Debt	**$1,061**	740	524
Other	**110**	58	45
	1,171	798	569
Capitalized	**(327)**	(232)	(231)
Expensed	**$ 844**	566	338
Research and Development Expenditures — expensed	**$ 136**	355*	44

**Includes $246 million of in-process research and development expenses related to the merger.*

Advertising Expenses*	**$ 70**	37	56

**Deferred amounts at December 31 were immaterial in all three years.*

Cash Dividends paid per common share	**$ 1.63**	1.48	1.40
Foreign Currency Transaction Gains (Losses) — after-tax			
E&P	**$ (50)**	(34)	2
R&M	**18**	9	3
Chemicals	**—**	—	—
Emerging Businesses	**(1)**	—	—
Corporate and Other	**67**	21	(8)
	$ 34	(4)	(3)

Note 27 — Related Party Transactions

Significant transactions with related parties were:

	Millions of Dollars		
	2003	2002	2001
Revenues (a)	**$3,812**	1,554	935
Purchases (b)	**3,316**	1,545	1,110
Operating expenses and selling, general and administrative expenses (c)	**560**	279	243
Net interest (income) expense (d)	**19**	(6)	8

(a) Our Exploration and Production (E&P) segment sells natural gas to Duke Energy Field Services, LLC (DEFS) and crude oil to the Malaysian Refining Company Sdn. Bhd (Melaka), among others, for processing and marketing. Natural gas liquids, solvents and petrochemical feedstocks are sold to Chevron Phillips Chemical Company LLC (CPChem) and refined products are sold primarily to CFJ Properties. Also, we charge several of our affiliates including CPChem, MSLP, Hamaca Holding LLC, and Venture Coke Company for the use of common facilities, such as steam generators, waste and water treaters, and warehouse facilities.

(b) We purchase natural gas and natural gas liquids from DEFS and CPChem for use in our refinery processes and other feedstocks from various affiliates. We purchase crude oil from Petrozuata C.A. and refined products from Melaka. We also pay fees to various pipeline equity companies for transporting finished refined products.

(c) We pay processing fees to various affiliates, the most significant being MSLP. Additionally, we pay contract drilling fees to deepwater drillship affiliates, crude oil transportation fees to pipeline equity companies, and commissions to the receivable monetization companies.

(d) We pay and/or receive interest to/from various affiliates including the receivable monetization companies and MSLP.

Elimination of our equity percentage share of profit or loss included in our inventory at December 31, 2003, 2002, and 2001, on the purchases from related parties described above was not material. Additionally, elimination of our profit or loss included in the related parties inventory at December 31, 2003, 2002, and 2001, on the revenues from related parties described above were not material.

Note 28 — Segment Disclosures and Related Information

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

(1) E&P — This segment primarily explores for and produces crude oil, natural gas, and natural gas liquids on a worldwide basis. At December 31, 2003, E&P was producing in the United States; the Norwegian and U.K. sectors of the North Sea; Canada; Nigeria; Venezuela; the Timor Sea; offshore Australia and China; Indonesia; the United Arab Emirates; Vietnam; and Russia. The E&P segment's U.S. and international operations are disclosed separately for reporting purposes.

(2) Midstream — Through both consolidated and equity interests, this segment gathers and processes natural gas produced by ConocoPhillips and others, and fractionates and markets natural gas liquids, primarily in the United States, Canada and Trinidad. The Midstream segment includes our 30.3 percent equity investment in DEFS.

(3) R&M — This segment refines, markets and transports crude oil and petroleum products, mainly in the United States, Europe and Asia. At December 31, 2003, we owned 12 refineries in the United States; one in the United Kingdom; one in Ireland; and had equity interests in one refinery in Germany, two in the Czech Republic, and one in Malaysia. The R&M segment's U.S. and international operations are disclosed separately for reporting purposes.

(4) 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.

(5) Emerging Businesses — This segment encompasses the development of new businesses beyond our traditional operations. Emerging Businesses includes new technologies related to natural gas conversion into clean fuels and related products (gas-to-liquids), technology solutions, power generation, and emerging technologies.

Corporate and Other includes general corporate overhead; all interest income and expense; preferred dividend requirements of capital trusts; discontinued operations; restructuring charges; goodwill resulting from the merger of Conoco and Phillips that had not yet been allocated to the operating segments; certain eliminations; and various other corporate activities. Corporate assets include all cash and cash equivalents.

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

Analysis of Results by Operating Segment

	Millions of Dollars		
	2003	2002	2001
Sales and Other Operating Revenues			
E&P			
United States	**$ 18,521**	7,222	5,879
International	**12,964**	4,850	2,266
Intersegment eliminations — U.S.	**(2,439)**	(1,304)	(534)
Intersegment eliminations — international	**(3,202)**	(484)	—
E&P	**25,844**	10,284	7,611
Midstream			
Total sales	**4,735**	2,049	1,193
Intersegment eliminations	**(1,431)**	(510)	(416)
Midstream	**3,304**	1,539	777
R&M			
United States	**57,222**	41,011	16,445
International	**19,454**	5,630	142
Intersegment eliminations — U.S.	**(1,815)**	(1,773)	(92)
Intersegment eliminations — international	**(13)**	—	—
R&M	**74,848**	44,868	16,495
Chemicals	**14**	13	—
Emerging Businesses	**178**	36	7
Corporate and Other	**8**	8	2
Consolidated sales and other operating revenues	**$104,196**	56,748	24,892
Depreciation, Depletion, Amortization and Impairments			
E&P			
United States	**$ 1,172**	999	817
International	**1,736**	735	324
Total E&P	**2,908**	1,734	1,141
Midstream	**54**	19	1
R&M			
United States	**551**	564	203
International	**140**	50	1
Total R&M	**691**	614	204
Chemicals	**—**	—	—
Emerging Businesses	**10**	4	—
Corporate and Other	**74**	29	24
Consolidated depreciation, depletion, amortization and impairments	**$ 3,737**	2,400	1,370
Equity in Earnings of Affiliates			
E&P			
United States	**$ 27**	29	9
International	**289**	162	19
Total E&P	**316**	191	28
Midstream	**138**	46	165
R&M			
United States	**89**	43	88
International	**5**	—	—
Total R&M	**94**	43	88
Chemicals	**(6)**	(16)	(240)
Emerging Businesses	**—**	(3)	—
Corporate and Other	**—**	—	—
Consolidated equity in earnings of affiliates	**$ 542**	261	41

	Millions of Dollars		
	2003	2002	2001
Income Taxes			
E&P			
United States	**$ 1,231**	473	670
International	**2,269**	1,337	913
Total E&P	**3,500**	1,810	1,583
Midstream	**83**	42	73
R&M			
United States	**652**	90	210
International	**64**	(11)	—
Total R&M	**716**	79	210
Chemicals	**(12)**	(18)	(89)
Emerging Businesses	**(51)**	(38)	(7)
Corporate and Other	**(492)**	(432)	(130)
Consolidated income taxes	**$ 3,744**	1,443	1,640
Net Income (Loss)			
E&P			
United States	**$ 2,374**	1,156	1,342
International	**1,928**	593	357
Total E&P	**4,302**	1,749	1,699
Midstream	**130**	55	120
R&M			
United States	**990**	138	395
International	**282**	5	2
Total R&M	**1,272**	143	397
Chemicals	**7**	(14)	(128)
Emerging Businesses	**(99)**	(310)*	(12)
Corporate and Other	**(877)**	(1,918)	(415)
Consolidated net income (loss)	**$ 4,735**	(295)	1,661

**Includes a non-cash $246 million write-off of acquired in-process research and development costs.*

	Millions of Dollars		
	2003	2002	2001
Investments In and Advances To Affiliates			
E&P			
United States	**$ 133**	156	13
International	**2,351**	2,184	573
Total E&P	**2,484**	2,340	586
Midstream	**394**	318	166
R&M			
United States	**777**	762	166
International	**517**	416	—
Total R&M	**1,294**	1,178	166
Chemicals	**2,059**	2,050	1,852
Emerging Businesses	**2**	—	—
Corporate and Other	**25**	14	18
Consolidated investments in and advances to affiliates	**$ 6,258**	5,900	2,788
Total Assets			
E&P			
United States	**$15,262**	14,196	9,501
International	**22,458**	19,526	5,280
Goodwill	**11,184**	15	15
Total E&P	**48,904**	33,737	14,796
Midstream	**1,736**	1,931	196
R&M			
United States	**17,172**	16,718	12,327
International	**5,020**	4,117	183
Goodwill	**3,900**	2,350	2,226
Total R&M	**26,092**	23,185	14,736
Chemicals	**2,094**	2,095	1,934
Emerging Businesses	**843**	737	2
Corporate and Other	**2,786**	15,151*	3,553
Consolidated total assets	**$82,455**	76,836	35,217

**Includes goodwill not yet allocated to reporting units of $12,079 million.*

	Millions of Dollars		
	2003	2002	2001
Capital Expenditures and Investments*			
E&P			
United States	**$1,418**	1,205	1,354
International	**3,090**	2,071	1,162
Total E&P	**4,508**	3,276	2,516
Midstream	**10**	5	—
R&M			
United States	**860**	676	423
International	**319**	164	5
Total R&M	**1,179**	840	428
Chemicals	—	60	6
Emerging Businesses	**284**	122	—
Corporate and Other	**188**	85	66
Consolidated capital expenditures and investments	**$6,169**	4,388	3,016

Includes dry hole costs.

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

	Millions of Dollars		
	2003	2002	2001
Interest income	**$ 104**	40	13
Interest expense	**844**	566	338
Significant non-cash items			
Impairments included in discontinued operations	**96**	1,048	—
Loss accruals related to retail site leases included in discontinued operations	—	477	—
Restructuring charges, net of benefits paid	—	269	—

Geographic Information

	Millions of Dollars					
	United States	Norway	United Kingdom	Canada	Other Foreign Countries	Worldwide Consolidated
2003						
Sales and Other Operating Revenues*	**$74,768**	**3,068**	**11,203**	**2,735**	**12,422**	**104,196**
Long-Lived Assets**	**$29,899**	**4,215**	**5,762**	**4,347**	**9,463**	**53,686**
2002						
Sales and Other Operating Revenues*	$46,674	1,850	3,387	997	3,840	56,748
Long-Lived Assets**	$28,492	3,767	4,969	3,460	8,242	48,930
2001						
Sales and Other Operating Revenues*	$22,466	1,322	380	42	682	24,892
Long-Lived Assets**	$19,955	1,484	654	29	2,799	24,921

**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 affiliates.*

Note 29 — New Accounting Standards

In December 2003, the FASB revised and reissued SFAS No. 132 (revised 2003), "Employers' Disclosures about Pensions and Other Postretirement Benefits — an amendment of FASB Statements No. 87, 88, and 106," which revises and requires additional disclosures about pension plans and other postretirement benefit plans. It does not change the measurement or recognition of those plans required by previous Financial Accounting Board Standards. We adopted the provisions of this Standard effective December 2003. Certain provisions of this Standard regarding disclosure of information about foreign plans and disclosure of estimated future benefit payments are not required until 2004. The adoption of the provisions applicable to 2003 did not have an impact on our results of operations or financial position, nor will the adoption of the additional provisions in 2004 have an impact on our results of operations or financial position.

In May 2003, the FASB issued SFAS No. 150, "Accounting for Certain Financial Instruments with Characteristics of Liabilities and Equity," to address the balance sheet classification of certain financial instruments that have characteristics of both liabilities and equity. This statement was immediately effective for all contracts created or modified after May 31, 2003, and became effective July 1, 2003, for all previously existing contracts. On November 7, 2003, the FASB issued FASB Staff Position No. FAS 150-3, which deferred certain provisions of SFAS No. 150. As a result of adopting this new accounting standard in the third quarter of 2003, and the subsequent November 7, 2003, deferral of certain provisions, there was no impact on our 2003 financial statements. We continue to monitor the deferral status of SFAS No. 150.

Oil and Gas Operations (Unaudited)

Exploration and Production

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, it is emphasized that 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.

Our disclosures by geographic area include the United States (U.S.), European North Sea (Norway and the United Kingdom), Asia Pacific, Canada and Other Areas. When we use equity accounting for operations that have proved reserves, these oil and gas operations are shown separately and designated as Equity Affiliates. In 2003 and 2002, these consisted of two heavy-oil projects in Venezuela, an oil development project in Northern Russia and a heavy-oil project in Canada. In 2001, this consisted of a heavy-oil project in Venezuela.

Amounts in 2002 were impacted by the merger of Conoco and Phillips (the merger) in late August 2002.

Proved Reserves Worldwide

Years Ended December 31	Crude Oil									
	Millions of Barrels									
	Consolidated Operations									
	Alaska	Lower 48	Total U.S.	European North Sea	Asia Pacific	Canada	Other Areas	Total	Equity Affiliates	Combined Total
Developed and Undeveloped										
End of 2000	1,604	112	1,716	609	136	2	112	2,575	613	3,188
Revisions	77	(2)	75	45	9	—	(5)	124	48	172
Improved recovery	67	1	68	12	—	—	—	80	—	80
Purchases	—	—	—	—	17	—	—	17	—	17
Extensions and discoveries	9	6	15	2	2	—	10	29	—	29
Production	(126)	(12)	(138)	(49)	(6)	—	(13)	(206)	(1)	(207)
Sales	—	—	—	—	—	—	(3)	(3)	—	(3)
End of 2001	1,631	105	1,736	619	158*	2	101	2,616	660	3,276
Revisions	32	(8)	24	(31)	(28)	5	(4)	(34)	(27)	(61)
Improved recovery	46	1	47	7	—	—	—	54	—	54
Purchases	—	132	132	405	124	101	99	861	733	1,594
Extensions and discoveries	14	6	20	6	9	1	13	49	4	53
Production	(120)	(14)	(134)	(72)	(9)	(5)	(15)	(235)	(13)	(248)
Sales	—	(2)	(2)	(20)	—	(13)	(1)	(36)	—	(36)
End of 2002	1,603	220	1,823	914	254**	91	193	3,275	1,357	4,632
Revisions	**35**	**(5)**	**30**	**15**	**40**	**(9)**	**(4)**	**72**	**48**	**120**
Improved recovery	**15**	**1**	**16**	**47**	**—**	**—**	**1**	**64**	**—**	**64**
Purchases	**—**	**—**	**—**	**—**	**5**	**—**	**—**	**5**	**1**	**6**
Extensions and discoveries	**19**	**4**	**23**	**4**	**10**	**223**	**10**	**270**	**8**	**278**
Production	**(119)**	**(19)**	**(138)**	**(106)**	**(24)**	**(11)**	**(27)**	**(306)**	**(37)**	**(343)**
Sales	**—**	**(15)**	**(15)**	**(9)**	**(21)**	**(20)**	**(25)**	**(90)**	**—**	**(90)**
End of 2003	**1,553**	**186**	**1,739**	**865**	**264**	**274**	**148**	**3,290**	**1,377**	**4,667**
Developed										
End of 2000	1,207	98	1,305	503	16	2	100	1,926	—	1,926
End of 2001	1,275	91	1,366	534	13	2	83	1,998	47	2,045
End of 2002	1,335	169	1,504	713	55	81	168	2,521	378	2,899
End of 2003	**1,365**	**163**	**1,528**	**454**	**95**	**51**	**137**	**2,265**	**529**	**2,794**

**Includes proved reserves of 17 million barrels attributable to a consolidated subsidiary in which there is a 13 percent minority interest.*
***Includes proved reserves of 14 million barrels attributable to a consolidated subsidiary in which there is a 10 percent minority interest.*

- Purchases in 2002 were primarily related to the merger.
- At the end of 2000, Other Areas included 2 million barrels of reserves in Venezuela in which we had an economic interest through risk-service contracts. These properties were sold in June 2001. Our net production related to these contracts was approximately 400,000 barrels in 2001 and 1,200,000 barrels in 2000.
- In addition to conventional crude oil, natural gas and natural gas liquids (NGL) proved reserves, we have proved oil sands reserves in Canada, associated with a Syncrude project totaling 265 million barrels at the end of 2003. For internal management purposes, we view these reserves and their development as part of our total exploration and production operations. However, U.S. Securities and Exchange Commission 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 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.	European North Sea	Asia Pacific	Canada	Other Areas	Total	Equity Affiliates	Combined Total
Developed and Undeveloped										
End of 2000	3,237	2,853	6,090	1,624	64	64	561	8,403	131	8,534
Revisions	60	9	69	(124)	(1)	(2)	65	7	14	21
Improved recovery	—	—	—	13	—	—	—	13	—	13
Purchases	—	12	12	10	10	—	—	32	—	32
Extensions and discoveries	5	405	410	23	265	—	109	807	—	807
Production	(141)	(261)	(402)	(121)	(21)	(7)	(19)	(570)	—	(570)
Sales	—	—	—	(8)	—	—	—	(8)	—	(8)
End of 2001	3,161	3,018	6,179	1,417	317*	55	716	8,684	145	8,829
Revisions	(27)	(70)	(97)	(20)	(60)	16	(15)	(176)	—	(176)
Improved recovery	5	1	6	14	—	—	—	20	—	20
Purchases	—	1,862	1,862	2,583	1,856	1,241	206	7,748	17	7,765
Extensions and discoveries	2	225	227	43	6	21	414	711	1	712
Production	(147)	(340)	(487)	(226)	(49)	(59)	(19)	(840)	(2)	(842)
Sales	(5)	(1)	(6)	(4)	—	(97)	(161)	(268)	—	(268)
End of 2002	2,989	4,695	7,684	3,807	2,070**	1,177	1,141	15,879	161	16,040
Revisions	**75**	**(140)**	**(65)**	**17**	**(79)**	**(51)**	**—**	**(178)**	**65**	**(113)**
Improved recovery	**6**	**1**	**7**	**51**	**—**	**—**	**1**	**59**	**—**	**59**
Purchases	**—**	**39**	**39**	**—**	**60**	**—**	**—**	**99**	**—**	**99**
Extensions and discoveries	**—**	**254**	**254**	**65**	**1,371**	**90**	**85**	**1,865**	**5**	**1,870**
Production	**(148)**	**(477)**	**(625)**	**(462)**	**(121)**	**(159)**	**(35)**	**(1,402)**	**(5)**	**(1,407)**
Sales	**—**	**(114)**	**(114)**	**(60)**	**(295)**	**(15)**	**(4)**	**(488)**	**—**	**(488)**
End of 2003	**2,922**	**4,258**	**7,180**	**3,418**	**3,006**	**1,042**	**1,188**	**15,834**	**226**	**16,060**
Developed										
End of 2000	2,969	2,564	5,533	1,059	1	54	335	6,982	—	6,982
End of 2001	2,969	2,684	5,653	1,053	245	45	491	7,487	3	7,490
End of 2002	2,806	4,302	7,108	3,278	832	1,098	517	12,833	28	12,861
End of 2003	**2,763**	**3,968**	**6,731**	**2,748**	**1,342**	**971**	**596**	**12,388**	**123**	**12,511**

**Includes proved reserves of 10 billion cubic feet attributable to a consolidated subsidiary in which there is a 13 percent minority interest.*
***Includes proved reserves of 10 billion cubic feet attributable to a consolidated subsidiary in which there is a 10 percent minority interest.*

- 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 plant or facility.
- Purchases in 2002 were related to the merger.
- Natural gas reserves are computed at 14.65 pounds per square inch absolute and 60 degrees Fahrenheit.

Years Ended December 31	Natural Gas Liquids									
	Millions of Barrels									
	Consolidated Operations									
	Alaska	Lower 48	Total U.S.	European North Sea	Asia Pacific	Canada	Other Areas	Total	Equity Affiliates	Combined Total
Developed and Undeveloped										
End of 2000	198	96	294	37	60	—	18	409	—	409
Revisions	(25)	2	(23)	—	5	—	(1)	(19)	—	(19)
Improved recovery	—	—	—	1	—	—	—	1	—	1
Purchases	—	—	—	—	10	—	—	10	—	10
Extensions and discoveries	—	2	2	—	—	—	—	2	—	2
Production	(9)	(7)	(16)	(2)	—	—	(1)	(19)	—	(19)
End of 2001	164	93	257	36	75*	—	16	384	—	384
Revisions	(4)	5	1	(1)	(11)	—	—	(11)	—	(11)
Improved recovery	—	1	1	—	—	—	—	1	—	1
Purchases	—	80	80	14	20	38	1	153	—	153
Extensions and discoveries	—	4	4	—	—	1	—	5	—	5
Production	(9)	(9)	(18)	(3)	—	(2)	(1)	(24)	—	(24)
Sales	—	—	—	—	—	(2)	(1)	(3)	—	(3)
End of 2002	151	174	325	46	84**	35	15	505	—	505
Revisions	**(2)**	**35**	**33**	**3**	**(5)**	**(1)**	**1**	**31**	**—**	**31**
Improved recovery	**—**	**—**	**—**	**2**	**—**	**—**	**—**	**2**	**—**	**2**
Purchases	**—**	**—**	**—**	**—**	**3**	**—**	**—**	**3**	**—**	**3**
Extensions and discoveries	**—**	**2**	**2**	**—**	**10**	**2**	**—**	**14**	**—**	**14**
Production	**(8)**	**(17)**	**(25)**	**(5)**	**—**	**(4)**	**(1)**	**(35)**	**—**	**(35)**
Sales	**—**	**(1)**	**(1)**	**—**	**(13)**	**(2)**	**—**	**(16)**	**—**	**(16)**
End of 2003	**141**	**193**	**334**	**46**	**79**	**30**	**15**	**504**	**—**	**504**
Developed										
End of 2000	197	94	291	29	—	1	17	338	—	338
End of 2001	163	92	255	31	—	—	16	302	—	302
End of 2002	151	166	317	40	—	30	15	402	—	402
End of 2003	**141**	**188**	**329**	**26**	**—**	**27**	**15**	**397**	**—**	**397**

**Includes proved reserves of 10 million barrels attributable to a consolidated subsidiary in which there is a 13 percent minority interest.*
***Includes proved reserves of 9 million barrels attributable to a consolidated subsidiary in which there is a 10 percent minority interest.*

- Natural gas liquids reserves include estimates of natural gas liquids to be extracted from our leasehold gas at our gas processing plants or facilities. Estimates are based at the wellhead and assume full extraction. Production above differs from natural gas liquids production per day delivered for sale primarily due to:
  (1) Natural gas consumed at the lease.
  (2) Natural gas liquids production delivered for sale includes only natural gas liquids extracted from our leasehold gas and sold by our Exploration and Production (E&P) segment, whereas the production above also includes natural gas liquids extracted from our leasehold gas at equity-affiliate or third-party facilities.
- Purchases in 2002 were related to the merger.

Results of Operations

Years Ended December 31	Millions of Dollars									
	Consolidated Operations									
	Alaska	Lower 48	Total U.S.	European North Sea	Asia Pacific	Canada	Other Areas	Total	Equity Affiliates	Combined Total
2003										
Sales	**$3,564**	**2,464**	**6,028**	**3,872**	**879**	**225**	**677**	**11,681**	**423**	**12,104**
Transfers	**103**	**545**	**648**	**903**	**142**	**841**	**77**	**2,611**	**266**	**2,877**
Other revenues	**(11)**	**93**	**82**	**8**	**33**	**31**	**10**	**164**	**34**	**198**
Total revenues	**3,656**	**3,102**	**6,758**	**4,783**	**1,054**	**1,097**	**764**	**14,456**	**723**	**15,179**
Production costs	**792**	**657**	**1,449**	**645**	**175**	**271**	**170**	**2,710**	**179**	**2,889**
Exploration expenses	**56**	**143**	**199**	**121**	**51**	**94**	**127**	**592**	**2**	**594**
Depreciation, depletion and amortization	**436**	**571**	**1,007**	**954**	**163**	**326**	**40**	**2,490**	**104**	**2,594**
Property impairments	**—**	**65**	**65**	**160**	**—**	**5**	**—**	**230**	**—**	**230**
Transportation costs	**666**	**188**	**854**	**266**	**40**	**40**	**23**	**1,223**	**20**	**1,243**
Other related expenses	**7**	**78**	**85**	**29**	**13**	**91**	**44**	**262**	**27**	**289**
Accretion	**25**	**18**	**43**	**50**	**5**	**11**	**2**	**111**	**2**	**113**
	1,674	**1,382**	**3,056**	**2,558**	**607**	**259**	**358**	**6,838**	**389**	**7,227**
Provision for income taxes	**595**	**486**	**1,081**	**1,539**	**225**	**57**	**362**	**3,264**	**83**	**3,347**
Results of operations for producing activities	**1,079**	**896**	**1,975**	**1,019**	**382**	**202**	**(4)**	**3,574**	**306**	**3,880**
Other earnings	**223**	**34**	**257**	**51**	**3**	**68***	**(46)**	**333**	**(51)**	**282**
Cumulative effect of accounting change	**143**	**(1)**	**142**	**20**	**—**	**(8)**	**(12)**	**142**	**(2)**	**140**
E&P net income (loss)	**$1,445**	**929**	**2,374**	**1,090**	**385**	**262**	**(62)**	**4,049**	**253**	**4,302**
2002										
Sales	$2,997	927	3,924	1,194	347	125	400	5,990	180	6,170
Transfers	102	401	503	1,315	—	235	—	2,053	62	2,115
Other revenues	(2)	3	1	63	7	7	14	92	12	104
Total revenues	3,097	1,331	4,428	2,572	354	367	414	8,135	254	8,389
Production costs	769	444	1,213	343	76	118	114	1,864	57	1,921
Exploration expenses	101	108	209	67	45	32	231	584	—	584
Depreciation, depletion and amortization	552	334	886	480	59	105	26	1,556	30	1,586
Property impairments	4	8	12	41	—	—	—	53	—	53
Transportation costs	681	87	768	125	10	—	5	908	8	916
Other related expenses	23	16	39	75	1	14	11	140	12	152
	967	334	1,301	1,441	163	98	27	3,030	147	3,177
Provision for income taxes	294	66	360	981	79	49	196	1,665	(18)	1,647
Results of operations for producing activities	673	268	941	460	84	49	(169)	1,365	165	1,530
Other earnings	197	18	215	10	(2)	24*	(4)	243	(24)	219
E&P net income (loss)	$ 870	286	1,156	470	82	73	(173)	1,608	141	1,749
2001										
Sales	$3,020	1,178	4,198	546	154	31	324	5,253	8	5,261
Transfers	119	119	238	1,039	—	—	—	1,277	—	1,277
Other revenues	34	26	60	23	(4)	5	—	84	1	85
Total revenues	3,173	1,323	4,496	1,608	150	36	324	6,614	9	6,623
Production costs	784	328	1,112	165	37	6	55	1,375	2	1,377
Exploration expenses	61	69	130	31	33	—	121	315	—	315
Depreciation, depletion and amortization	531	203	734	233	22	4	27	1,020	2	1,022
Property impairments	—	—	—	—	—	—	23	23	—	23
Transportation costs	726	77	803	60	—	3	6	872	—	872
Other related expenses	2	5	7	(8)	5	1	23	28	2	30
	1,069	641	1,710	1,127	53	22	69	2,981	3	2,984
Provision for income taxes	392	173	565	779	22	7	117	1,490	—	1,490
Results of operations for producing activities	677	468	1,145	348	31	15	(48)	1,491	3	1,494
Other earnings	189	8	197	17	—	—	(9)	205	—	205
E&P net income (loss)	$ 866	476	1,342	365	31	15	(57)	1,696	3	1,699

**Includes $63 million and $27 million in 2003 and 2002, respectively, for a Syncrude oil project in Canada that is defined as a mining operation by U.S. Securities and Exchange Commission regulations.*

- Results of operations for producing activities consist of all the activities within the E&P organization, 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 non-E&P activities, including 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, including net gains of approximately $165 million in 2003; certain amounts resulting from the purchase and sale of hydrocarbons; and other miscellaneous income.
- Production costs consist of costs incurred to operate and maintain wells and related equipment and facilities used in the production of petroleum liquids and natural gas. These costs also include taxes other than income taxes, depreciation of support equipment and administrative expenses related to the

production activity. Excluded are transportation costs, fees for processing natural gas to natural gas liquids, depreciation, depletion and amortization of capitalized acquisition, exploration and development costs.

- 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.

  Exploration expenses for Other Areas in 2002 included $77 million for the impairment of a substantial portion of the company's investment in deepwater Block 34, offshore Angola. Initial results released in early May 2002 indicated that the first exploratory well drilled in Block 34 was a dry hole, resulting in our reassessment of the fair value of the remainder of the block. In December 2003, a second exploration well was drilled, which encountered non-commercial gas and was plugged and abandoned. As a result, additional exploration expenses in 2003 included $34 million related to the impairment of the remaining value of this block.
- Depreciation, depletion and amortization (DD&A) in Results of Operations differs from that shown for total E&P in Note 28 — 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.
- Property impairments for the European North Sea in 2003 included a charge of $94 million related to the repeal of the Norway Removal Grant Act.
- 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. In 2003, this included a $105 million benefit related to the repeal of the Norway Removal Grant Act, a $95 million benefit related to the reduction in the Canada and Alberta provincial tax rates, a $46 million benefit related to the impairment of Angola Block 34, and a $27 million benefit related to the re-alignment agreement of the Bayu-Undan project in the Timor Sea.
- Other earnings consist of activities within the E&P segment that are not a part of the "Results of operations for producing activities." These non-producing activities include pipeline and marine operations, liquefied natural gas operations, a Canadian Syncrude operation, and crude oil and gas marketing activities.

Statistics

Net Production	**2003**	2002	2001
	Thousands of Barrels Daily		
Crude Oil			
Alaska	**325**	331	339
Lower 48	**54**	40	34
United States	**379**	371	373
European North Sea	**290**	196	136
Asia Pacific	**61**	24	17
Canada	**30**	13	1
Other areas	**72**	43	34
Total consolidated	**832**	647	561
Equity affiliates	**102**	35	2
	934	682	563
Natural Gas Liquids*			
Alaska	**23**	24	25
Lower 48	**25**	8	1
United States	**48**	32	26
European North Sea	**9**	8	7
Canada	**10**	4	—
Other areas	**2**	2	2
	69	46	35

**Represents amounts extracted attributable to E&P operations (see natural gas liquids reserves for further discussion). Includes for 2003, 2002 and 2001, 15,000, 14,000, and 15,000 barrels daily in Alaska, respectively, that were sold from the Prudhoe Bay lease to the Kuparuk lease for reinjection to enhance crude oil production.*

Natural Gas*	Millions of Cubic Feet Daily		
Alaska	**184**	175	177
Lower 48	**1,295**	928	740
United States	**1,479**	1,103	917
European North Sea	**1,215**	595	308
Asia Pacific	**318**	137	51
Canada	**435**	165	18
Other areas	**63**	43	41
Total consolidated	**3,510**	2,043	1,335
Equity affiliates	**12**	4	—
	3,522	2,047	1,335

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

Average Sales Prices			
Crude Oil			
Per Barrel			
Alaska	**$28.87**	23.75	23.60
Lower 48	**28.76**	24.48	23.27
United States	**28.85**	23.83	23.57
European North Sea	**28.83**	25.24	24.09
Asia Pacific	**27.87**	26.33	24.27
Canada	**25.06**	22.87	26.96
Other areas	**27.68**	24.76	24.32
Total international	**28.27**	25.14	24.16
Total consolidated	**28.54**	24.38	23.77
Equity affiliates	**18.58**	18.41	12.36
Worldwide	**27.47**	24.07	23.74

	2003	2002	2001
Average Sales Prices *(continued)*			
Natural Gas Liquids			
Per Barrel			
Alaska	**$ 29.04**	23.48	23.61
Lower 48	**20.02**	15.66	22.47
United States	**22.30**	20.00	23.49
European North Sea	**21.34**	17.38	17.12
Canada	**23.93**	20.39	18.77
Other areas	**7.24**	7.23	7.22
Total international	**21.39**	17.47	14.61
Worldwide	**21.95**	18.93	19.74
Natural Gas (Lease)			
Per Thousand Cubic Feet			
Alaska	**$ 1.76**	1.85	1.75
Lower 48	**4.76**	2.79	3.68
United States	**4.62**	2.75	3.56
European North Sea	**3.63**	3.00	3.16
Asia Pacific	**3.56**	2.34	.43
Canada	**4.48**	3.03	3.80
Other areas	**.58**	.48	.57
Total international	**3.71**	2.79	2.60
Total consolidated	**4.07**	2.77	3.23
Equity affiliates	**4.44**	2.71	—
Worldwide	**4.07**	2.77	3.23
Average Production Costs			
Per Barrel of Oil Equivalent			
Alaska	**$ 5.73**	5.48	5.46
Lower 48	**6.10**	6.00	5.67
United States	**5.89**	5.66	5.52
European North Sea	**3.52**	3.10	2.33
Asia Pacific	**4.20**	4.45	3.98
Canada	**6.60**	7.26	4.08
Other areas	**5.51**	5.99	3.52
Total international	**4.25**	3.99	2.70
Total consolidated	**5.00**	4.94	4.60
Equity affiliates	**4.72**	4.38	2.74
Worldwide	**4.98**	4.92	4.60
Depreciation, Depletion and Amortization Per Barrel of Oil Equivalent			
Alaska	**$ 3.15**	3.94	3.70
Lower 48	**5.31**	4.52	3.51
United States	**4.10**	4.14	3.64
European North Sea	**5.21**	4.34	3.28
Asia Pacific	**3.92**	3.46	2.37
Canada	**7.94**	6.46	2.72
Other areas	**1.30**	1.37	1.73
Total international	**5.00**	4.11	2.94
Total consolidated	**4.59**	4.13	3.41
Equity affiliates	**2.74**	2.30	2.74
Worldwide	**4.47**	4.06	3.41

Net Wells Completed*	Productive			Dry		
	2003	2002	2001	**2003**	2002	2001
Exploratory						
Alaska	**—**	—	1	**1**	4	1
Lower 48	**35**	29	63	**23**	6	3
United States	**35**	29	64	**24**	10	4
European North Sea	**1**	**	**	**2**	2	1
Asia Pacific	**—**	**	2	**2**	7	1
Canada	**72**	19	—	**16**	2	—
Other areas	**—**	2	—	**	**	—
Total consolidated	**108**	50	66	**44**	21	6
Equity affiliates	**23**	3	—	**6**	1	—
	131	53	66	**50**	22	6
Development						
Alaska	**39**	48	47	**1**	1	2
Lower 48	**283**	283	333	**7**	14	11
United States	**322**	331	380	**8**	15	13
European North Sea	**12**	11	4	**—**	—	—
Asia Pacific	**19**	9	1	**2**	—	—
Canada	**114**	20	5	**5**	1	—
Other areas	**11**	4	1	**—**	**	—
Total consolidated	**478**	375	391	**15**	16	13
Equity affiliates	**98**	49	20	**3**	1	—
	576	424	411	**18**	17	13

**Includes wildcat and production step-out wells. Excludes farmout arrangements.*
***Our total proportionate interest was less than one.*

Wells at Year-End 2003

	In Progress*		Productive** Oil		Productive** Gas	
	Gross	Net	Gross	Net	Gross	Net
Alaska	**16**	**10**	**1,460**	**662**	**27**	**18**
Lower 48	**118**	**80**	**9,343**	**4,412**	**14,772**	**8,545**
United States	**134**	**90**	**10,803**	**5,074**	**14,799**	**8,563**
European North Sea	**20**	**5**	**584**	**98**	**253**	**85**
Asia Pacific	**41**	**24**	**381**	**177**	**55**	**28**
Canada	**73**	**53**	**2,153**	**1,419**	**4,754**	**3,061**
Other areas	**18**	**3**	**506**	**135**	**13**	**3**
Total consolidated	**286**	**175**	**14,427**	**6,903**	**19,874**	**11,740**
Equity affiliates	**7**	**3**	**2,198**	**919**	**212**	**75**
	293	**178**	**16,625**	**7,822**	**20,086**	**11,815**

**Includes wells that have been temporarily suspended.*
***Includes 3,274 gross and 1,970 net multiple completion wells.*

Acreage at December 31, 2003	Thousands of Acres	
	Gross	Net
Developed		
Alaska	**1,021**	**568**
Lower 48	**5,347**	**3,085**
United States	**6,368**	**3,653**
European North Sea	**1,154**	**336**
Asia Pacific	**4,538**	**1,993**
Canada	**4,705**	**2,328**
Other areas	**544**	**104**
Total consolidated	**17,309**	**8,414**
Equity affiliates	**695**	**239**
	18,004	**8,653**
Undeveloped		
Alaska	**2,164**	**1,406**
Lower 48	**2,883**	**1,681**
United States	**5,047**	**3,087**
European North Sea	**6,056**	**1,783**
Asia Pacific	**27,223**	**17,473**
Canada	**12,604**	**8,076**
Other areas	**34,163**	**12,748**
Total consolidated	**85,093**	**43,167**
Equity affiliates	**1,826**	**806**
	86,919	**43,973**

Costs Incurred

	Millions of Dollars									
	Consolidated Operations									
	Alaska	Lower 48	Total U.S.	European North Sea	Asia Pacific	Canada	Other Areas	Total	Equity Affiliates	Combined Total
2003										
Unproved property acquisition	**$ 10**	**7**	**17**	**—**	**3**	**—**	**64**	**84**	**—**	**84**
Proved property acquisition	**—**	**6**	**6**	**(92)**	**27**	**20**	**(43)**	**(82)**	**(10)**	**(92)**
	10	**13**	**23**	**(92)**	**30**	**20**	**21**	**2**	**(10)**	**(8)**
Exploration	**65**	**164**	**229**	**105**	**101**	**152**	**167**	**754**	**12**	**766**
Development	**386**	**693**	**1,079**	**1,075**	**844**	**197**	**194**	**3,389**	**333**	**3,722**
	$461	**870**	**1,331**	**1,088**	**975**	**369**	**382**	**4,145**	**335**	**4,480**
2002										
Unproved property acquisition	$ 9	315	324	679	388	559	194	2,144	—	2,144
Proved property acquisition	—	3,420	3,420	3,719	1,385	2,003	97	10,624	1,671	12,295
	9	3,735	3,744	4,398	1,773	2,562	291	12,768	1,671	14,439
Exploration	93	112	205	61	55	58	202	581	1	582
Development	434	409	843	406	787	46	122	2,204	467	2,671
	$536	4,256	4,792	4,865	2,615	2,666	615	15,553	2,139	17,692
2001										
Unproved property acquisition	$ 17	24	41	—	—	—	165	206	—	206
Proved property acquisition	—	13	13	—	63	—	—	76	—	76
	17	37	54	—	63	—	165	282	—	282
Exploration	91	57	148	44	38	—	185	415	—	415
Development	612	312	924	169	349	3	52	1,497	420	1,917
	$720	406	1,126	213	450	3	402	2,194	420	2,614

- Costs incurred include capitalized and expensed items.
- Acquisition costs include the costs of acquiring proved and unproved oil and gas properties. Proved property acquisition costs in 2003 included net negative merger-related adjustments totaling $178 million. Acquisition costs in 2002 related primarily to the merger.
- 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.
- Approximately $1,211 million of properties, plants and equipment adjustments related to the cumulative effect of accounting changes in connection with the implementation of SFAS No. 143, "Accounting for Asset Retirement Obligations," has been excluded from the 2003 costs incurred.
- Costs incurred for the European North Sea in 2003 included approximately $430 million of increased properties, plants and equipment related to the repeal of the Norway Removal Grant Act.

Capitalized Costs

At December 31	Millions of Dollars									
	Consolidated Operations									
	Alaska	Lower 48	Total U.S.	European North Sea	Asia Pacific	Canada	Other Areas	Total	Equity Affiliates	Combined Total
2003										
Proved properties	**$7,664**	**7,388**	**15,052**	**11,534**	**3,835**	**2,700**	**918**	**34,039**	**3,252**	**37,291**
Unproved properties	**936**	**458**	**1,394**	**509**	**642**	**658**	**1,059**	**4,262**	**—**	**4,262**
	8,600	**7,846**	**16,446**	**12,043**	**4,477**	**3,358**	**1,977**	**38,301**	**3,252**	**41,553**
Accumulated depreciation, depletion and amortization	**2,166**	**2,481**	**4,647**	**4,261**	**421**	**561**	**602**	**10,492**	**161**	**10,653**
	$6,434	**5,365**	**11,799**	**7,782**	**4,056**	**2,797**	**1,375**	**27,809**	**3,091**	**30,900**
2002										
Proved properties	$7,037	7,737	14,774	9,600	3,140	2,023	692	30,229	2,847	33,076
Unproved properties	849	489	1,338	764	582	546	974	4,204	—	4,204
	7,886	8,226	16,112	10,364	3,722	2,569	1,666	34,433	2,847	37,280
Accumulated depreciation, depletion and amortization	1,636	2,891	4,527	3,257	205	182	456	8,627	37	8,664
	$6,250	5,335	11,585	7,107	3,517	2,387	1,210	25,806	2,810	28,616

- Capitalized costs include the cost of equipment and facilities for oil and gas producing activities. These costs include the activities of our E&P organization, excluding pipeline and marine operations, liquefied natural gas operations, a Canadian Syncrude operation, and crude oil and natural gas marketing activities.
- 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.	European North Sea	Asia Pacific	Canada	Other Areas	Total	Equity Affiliates	Combined Total
2003										
Future cash inflows	**$54,351**	**29,865**	**84,216**	**41,125**	**18,277**	**10,107**	**5,075**	**158,800**	**32,622**	**191,422**
Less:										
Future production and transportation costs	**21,557**	**7,559**	**29,116**	**10,429**	**4,480**	**3,974**	**2,068**	**50,067**	**5,823**	**55,890**
Future development costs	**4,104**	**1,404**	**5,508**	**5,358**	**1,163**	**1,111**	**283**	**13,423**	**1,510**	**14,933**
Future income tax provisions	**9,879**	**5,162**	**15,041**	**15,616**	**4,487**	**1,084**	**2,176**	**38,404**	**8,049**	**46,453**
Future net cash flows	**18,811**	**15,740**	**34,551**	**9,722**	**8,147**	**3,938**	**548**	**56,906**	**17,240**	**74,146**
10 percent annual discount	**9,323**	**8,084**	**17,407**	**3,234**	**3,348**	**1,703**	**152**	**25,844**	**11,061**	**36,905**
Discounted future net cash flows	**$ 9,488**	**7,656**	**17,144**	**6,488**	**4,799**	**2,235**	**396**	**31,062**	**6,179**	**37,241**
2002										
Future cash inflows	$54,497	28,679	83,176	41,280	16,581	8,076	6,073	155,186	32,983	188,169
Less:										
Future production and transportation costs	26,035	7,763	33,798	7,974	3,764	1,885	1,639	49,060	4,992	54,052
Future development costs	2,927	1,168	4,095	2,989	1,821	617	428	9,950	1,698	11,648
Future income tax provisions	7,665	5,349	13,014	20,075	3,917	2,361	2,995	42,362	8,501	50,863
Future net cash flows	17,870	14,399	32,269	10,242	7,079	3,213	1,011	53,814	17,792	71,606
10 percent annual discount	9,097	7,405	16,502	3,998	3,272	1,422	458	25,652	11,585	37,237
Discounted future net cash flows	$ 8,773	6,994	15,767	6,244	3,807*	1,791	553	28,162	6,207	34,369
2001										
Future cash inflows	$33,138	9,441	42,579	16,421	4,258	174	2,454	65,886	11,581	77,467
Less:										
Future production and transportation costs	20,541	4,241	24,782	2,474	843	52	583	28,734	3,483	32,217
Future development costs	3,071	530	3,601	875	918	9	161	5,564	1,282	6,846
Future income tax provisions	1,797	1,253	3,050	9,151	1,409	8	1,187	14,805	2,133	16,938
Future net cash flows	7,729	3,417	11,146	3,921	1,088	105	523	16,783	4,683	21,466
10 percent annual discount	3,297	1,821	5,118	1,607	760	44	259	7,788	3,687	11,475
Discounted future net cash flows	$ 4,432	1,596	6,028	2,314	328**	61	264	8,995	996	9,991

Includes $139 million attributable to a consolidated subsidiary in which there is a 10 percent minority interest.

***Includes $17 million attributable to a consolidated subsidiary in which there is a 13 percent minority interest.*

Excludes discounted future net cash flows from Canadian Syncrude of $1,048 million in 2003 and $869 million in 2002.

Sources of Change in Discounted Future Net Cash Flows

	Millions of Dollars								
	Consolidated Operations			Equity Affiliates			Total		
	2003	2002	2001	**2003**	2002	2001	**2003**	2002	2001
Discounted future net cash flows at the beginning of the year	**$ 28,162**	8,995	18,782	**6,207**	996	1,635	**34,369**	9,991	20,417
Changes during the year									
Revenues less production and transportation costs for the year	**(10,359)**	(5,271)	(4,283)	**(490)**	(177)	(6)	**(10,849)**	(5,448)	(4,289)
Net change in prices, and production and transportation costs	**4,388**	15,566	(14,668)	**(862)**	2,734	(1,552)	**3,526**	18,300	(16,220)
Extensions, discoveries and improved recovery, less estimated future costs	**3,237**	1,284	757	**31**	22	—	**3,268**	1,306	757
Development costs for the year	**3,389**	2,204	1,497	**333**	467	420	**3,722**	2,671	1,917
Changes in estimated future development costs	**(3,151)**	(1,843)	(1,013)	**(193)**	(108)	(17)	**(3,344)**	(1,951)	(1,030)
Purchases of reserves in place, less estimated future costs	**203**	22,161	130	**4**	4,781	—	**207**	26,942	130
Sales of reserves in place, less estimated future costs	**(1,722)**	(563)	(9)	**—**	(16)	—	**(1,722)**	(579)	(9)
Revisions of previous quantity estimates*	**83**	(185)	15	**202**	(712)	38	**285**	(897)	53
Accretion of discount	**4,738**	1,540	2,877	**852**	177	260	**5,590**	1,717	3,137
Net change in income taxes	**2,094**	(15,726)	4,909	**95**	(1,957)	218	**2,189**	(17,683)	5,127
Other	**—**	—	1	**—**	—	—	**—**	—	1
Total changes	**2,900**	19,167	(9,787)	**(28)**	5,211	(639)	**2,872**	24,378	(10,426)
Discounted future net cash flows at year-end	**$ 31,062**	28,162	8,995	**6,179**	6,207	996	**37,241**	34,369	9,991

**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)

	2003	2002	2001	2000	1999
Selected Income Data					
Sales and other operating revenues (includes excise taxes on petroleum products sales)	**$104,196**	56,748	24,892	22,155	14,988
Total revenues	**$105,097**	57,201	25,030	22,539	15,260
Income from continuing operations	**$ 4,593**	698	1,601	1,848	604
Effective income tax rate	**44.9%**	67.4	50.6	50.7	48.7
Net income (loss)	**$ 4,735**	(295)	1,661	1,862	609
Selected Balance Sheet Data					
Current assets	**$ 11,192**	10,903	6,498	2,752	2,914
Net properties, plants and equipment	**$ 47,428**	43,030	22,133	14,644	10,950
Total assets	**$ 82,455**	76,836	35,217	20,509	15,201
Current liabilities	**$ 14,011**	12,816	4,821	3,502	2,531
Long-term debt	**$ 16,340**	18,917	8,610	6,622	4,271
Total debt	**$ 17,780**	19,766	8,654	6,884	4,302
Mandatorily redeemable preferred securities of trust subsidiaries	**$ —**	350	650	650	650
Other minority interests	**$ 842**	651	5	1	1
Common stockholders' equity	**$ 34,366**	29,517	14,340	6,093	4,549
Percent of total debt to capital*	**34%**	39	37	51	45
Current ratio	**.8**	.9	1.3	.8	1.2
Selected Statement of Cash Flows Data					
Net cash provided by operating activities from continuing operations	**$ 9,167**	4,776	3,526	3,984	1,934
Net cash provided by operating activities	**$ 9,356**	4,978	3,559	4,014	1,941
Capital expenditures and investments**	**$ 6,169**	4,388	3,016	2,017	1,686
Cash dividends paid on common stock	**$ 1,107**	684	403	346	344
Other Data					
Per average common share outstanding					
Income from continuing operations					
Basic	**$ 6.75**	1.45	5.46	7.26	2.39
Diluted	**$ 6.70**	1.44	5.43	7.21	2.37
Net income (loss)					
Basic	**$ 6.96**	(.61)	5.67	7.32	2.41
Diluted	**$ 6.91**	(.61)	5.63	7.26	2.39
Cash dividends paid on common stock	**$ 1.63**	1.48	1.40	1.36	1.36
Common stockholders' equity per share (book value)	**$ 50.33**	43.56	37.52	23.86	17.94
Common shares outstanding at year-end (in millions)	**682.8**	677.6	382.2	255.4	253.6
Average common shares outstanding (in millions)					
Basic	**680.5**	482.1	293.0	254.5	252.8
Diluted	**685.4**	485.5	295.0	256.3	254.4
Common stockholders at year-end (in thousands)	**55.6**	60.9	54.7	49.2	51.7
Employees at year-end (in thousands)	**39.0**	57.3	38.7	12.4***	15.9

**Capital includes total debt, mandatorily redeemable preferred securities of trust subsidiaries, other minority interests and common stockholders' equity.*
***Excludes acquisitions, net of cash acquired.*
****Excludes 3,400 employees who were under contract to Chevron Phillips Chemical Company LLC (CPChem) from July 1, 2000, through December 31, 2000. Effective January 1, 2001, those employees became employees of CPChem.*

5-Year Operating Review

E&P	**2003**	2002	2001	2000	1999
	Thousands of Barrels Daily				
Net Crude Oil Production					
United States	**379**	371	373	241	50
European North Sea	**290**	196	136	139	133
Asia Pacific	**61**	24	17	19	15
Canada	**30**	13	1	6	7
Other areas	**72**	43	34	32	26
Total consolidated	**832**	647	561	437	231
Equity affiliates	**102**	35	2	—	—
	934	682	563	437	231
Net Natural Gas Liquids Production					
United States	**48**	32	26	20	2
European North Sea	**9**	8	7	7	6
Canada	**10**	4	—	1	1
Other areas	**2**	2	2	1	2
	69	46	35	29	11
Net Natural Gas Production*	Millions of Cubic Feet Daily				
United States	**1,479**	1,103	917	928	950
European North Sea	**1,215**	595	308	350	346
Asia Pacific	**318**	137	51	—	—
Canada	**435**	165	18	83	91
Other areas	**63**	43	41	33	6
Total consolidated	**3,510**	2,043	1,335	1,394	1,393
Equity affiliates	**12**	4	—	—	—
	3,522	2,047	1,335	1,394	1,393

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

	Thousands of Barrels Daily				
Syncrude Production	**19**	8	—	—	—
Net Oil and Gas Acreage	Millions of Acres				
United States	**7**	7	5	5	3
International	**45**	94	21	29	33
Total consolidated	**52**	101	26	34	36
Equity affiliates	**1**	1	—	—	—
	53	102	26	34	36
Oil and Gas Wells	Net Wells				
United States					
Oil	**5,074**	3,561	2,430	2,450	1,832
Gas and condensate	**8,563**	7,601	3,686	3,333	2,936
International					
Oil	**1,829**	2,851	134	178	740
Gas and condensate	**3,177**	3,588	99	99	396
Total consolidated	**18,643**	17,601	6,349	6,060	5,904
Equity affiliates	**994**	938	22	—	—
	19,637	18,539	6,371	6,060	5,904
Well Completions					
United States					
Exploratory	**59**	39	68	50	2
Development	**330**	346	393	269	122
International					
Exploratory	**93**	32	4	18	15
Development	**163**	45	11	17	27
Total consolidated	**645**	462	476	354	166
Equity affiliates	**130**	54	20	—	—
	775	516	496	354	166

Midstream	**2003**	2002	2001	2000	1999
	Thousands of Barrels Daily				
Natural Gas Liquids Extracted*	**219**	156	120	131	156

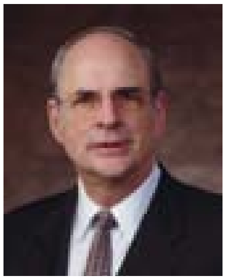
**Includes ConocoPhillips' share of equity affiliates.*

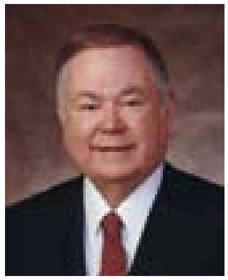
R&M					
Refinery Operations*					
United States					
Rated crude oil capacity**	**2,168**	1,829	732	335	330
Crude oil runs	**2,074**	1,661	686	303	326
Refinery production	**2,301**	1,847	795	365	385
International					
Rated crude oil capacity**	**442**	195	22	—	—
Crude oil runs	**385**	152	20	—	—
Refinery production	**412**	164	19	—	—
Petroleum Products Sales					
United States					
Automotive gasoline	**1,369**	1,230	537	298	285
Distillates	**575**	502	225	130	126
Aviation fuels	**180**	185	78	41	36
Other products	**492**	372	220	50	34
	2,616	2,289	1,060	519	481
International	**430**	162	10	43	37
	3,046	2,451	1,070	562	518

**Includes ConocoPhillips' share of equity affiliates.*
***Weighted-average crude oil capacity for the period, including the refineries acquired in the Tosco acquisition in September 2001 and the refineries acquired as a result of the merger. Actual capacity at year-end 2002 and 2001 was 2,166,000 and 1,656,000 barrels per day, respectively, in the United States and 440,000 and 72,000 barrels per day, respectively, internationally.*

ConocoPhillips Board of Directors

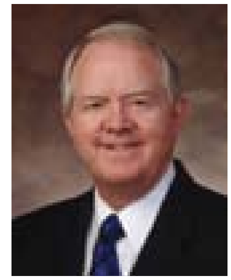

Richard H. Auchinleck


Norman R. Augustine

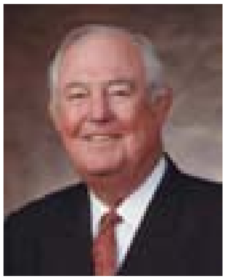

David L. Boren


James E. Copeland Jr.


Kenneth M. Duberstein

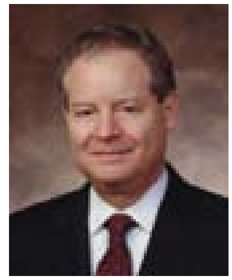

Archie W. Dunham

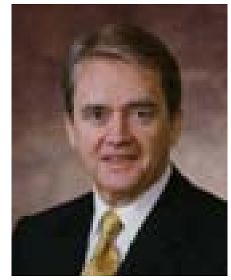

Ruth R. Harkin

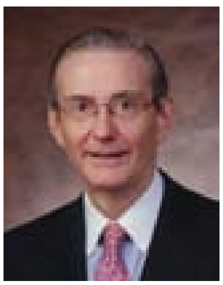

Larry D. Horner


Charles C. Krulak


Frank A. McPherson


J.J. Mulva


William K. Reilly


William R. Rhodes


J. Stapleton Roy


Victoria J. Tschinkel


Kathryn C. Turner

Richard H. Auchinleck, 52, president and CEO of Gulf Canada Resources Limited from February 1998 to June 2001. Chief operating officer of Gulf Canada from July 1997 to February 1998. CEO for Gulf Indonesia Resources Limited from September 1997 to February 1998. Also a director of Sonic Mobility Inc., Enbridge Commercial Trust and Telus Corporation. Lives in Calgary, Alberta, Canada. (1, 5)

Norman R. Augustine, 68, chairman of the board of directors of Lockheed Martin Corporation from August 1997 through March 1998. Chief executive officer of Lockheed Martin from January 1996 through July 1997. Also a director of The Black & Decker Corporation, Lockheed Martin Corporation and The Procter & Gamble Company. Lives in Potomac, Md. (2, 3, 4)

David L. Boren, 62, president of the University of Oklahoma since 1994. Former U.S. Senator from Oklahoma and former governor of Oklahoma. Also a director of AMR Corporation, Texas Instruments Incorporated and Torchmark Corporation. Lives in Norman, Okla. (5)

James E. Copeland Jr., 59, elected to ConocoPhillips board 2004. CEO of Deloitte & Touche USA, and its parent company, Deloitte & Touche Tohmatsu, from 1999 to 2003. A director of Coca-Cola Enterprises and Equifax. Also senior fellow for corporate governance with U.S. Chamber of Commerce and a global scholar with the Robinson School of Business at Georgia State University. Lives in Duluth, Ga. (1)

Kenneth M. Duberstein, 59, 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 and deputy undersecretary of Labor during the Ford administration. Sits on the board of governors for the NASD and the American Stock Exchange. Also a director of The Boeing Company, Fannie Mae, Fleming Companies, Inc. and The St. Paul Companies, Inc. Lives in Washington, D.C. (2, 4)

Archie W. Dunham, 65, chairman of the board of directors. Previously, chairman of the board, president and CEO of Conoco Inc. from 1999 to 2002. Joined Conoco in 1966 and became president and CEO in 1996 and chairman of the board in 1999. Serves as chairman of the National Association of Manufacturers. Also a director of the American Petroleum Institute, a past chairman of the National Petroleum Council and the U.S. Energy Association, and a member of The Business Council and The Business Roundtable. Serves as a director of the Memorial Hermann Healthcare System, senior chairman and trustee of the Houston Grand Opera, and trustee of the Smithsonian Institution and the George Bush Presidential Library. Also a director of Louisiana-Pacific Corporation, Phelps Dodge Corporation and Union Pacific Corporation. (2)

Ruth R. Harkin, 59, senior vice president, international affairs and government relations, for United Technologies Corporation and chair of United Technologies International, UTC's international representation arm, since June 1997. Lives in Alexandria, Va. (3)

Larry D. Horner, 69, chairman of Pacific USA Holdings Corporation from August 1994 to June 2001. Past chairman and CEO of KPMG Peat Marwick. Also a director of Atlantis Plastics, Inc., Technical Olympic USA, Inc., UTStarcom, Inc. and Clinical Data, Inc. Lives in San Jose del Cabo, BCS, Mexico. (1)

Charles C. Krulak, 62, chairman and CEO of MBNA Europe Bank Limited since January 2001. During his 35-year career in the Marine Corps, Gen. Krulak served two tours of duty in Vietnam and rose through several command and staff positions to become commandant of the Marine Corps and a member of the Joint Chiefs of Staff, June 1995 to September 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. Lives in Chester, Chesire, United Kingdom. (3, 4)

Frank A. McPherson, 70, chairman and CEO of Kerr-McGee Corporation until 1997, having held those positions since 1983. Also a director of BOK Financial Corporation, Tri-Continental Corporation and the Seligman Group of Mutual Funds. Lives in Oklahoma City, Okla. (1, 2)

J.J. Mulva, 57, president and CEO of ConocoPhillips. Chairman, president and CEO of Phillips from 1999 until August 2002. President and chief operating officer from 1994 to 1999. Joined Phillips in 1973; elected to board in 1994. Also a director of M.D. Anderson Cancer Center, the American Petroleum Institute and member of The Business Council and The Business Roundtable. Serves as a trustee of the Boys and Girls Clubs of America. (2)

William K. Reilly, 64, president and CEO of Aqua International Partners, an investment group that focuses on water projects and companies in developing countries, since June 1997. Also a director of E.I. du Pont de Nemours and Company, Ionics, Incorporated and Royal Caribbean Cruises Ltd. Lives in San Francisco, Calif. (5)

William R. Rhodes, 68, chairman of Citicorp/Citibank from February 2003 to present. Senior vice chairman of Citigroup, Inc. since December 2001. Senior vice chairman of Citicorp/Citibank from January 2002 to February 2003. Vice chairman of Citigroup, Inc. from March 1999 to December 2001. Vice chairman of Citicorp/Citibank from July 1991 to December 2001. Lives in New York, N.Y. (3)

J. Stapleton Roy, 68, managing director of Kissinger Associates, Inc. since January 2001. Assistant secretary of State for intelligence and research from 1999 to 2000. He 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 an advisory director of Freeport McMoRan Copper & Gold, Inc. Lives in Bethesda, Md. (4)

Victoria J. Tschinkel, 56, director of the Florida Nature Conservancy since January 2003. Senior environmental consultant to Landers & Parsons, a Tallahassee law firm, from 1987 to 2002. Former secretary of the Florida Department of Environmental Regulation. Lives in Tallahassee, Fla. (2, 5)

Kathryn C. Turner, 56, chairperson and CEO of Standard Technology, Inc., a management and technology solutions consulting firm with a focus in the healthcare sector she founded in 1985. Also a director of Carpenter Technology Corporation, Schering-Plough Corporation and Tribune Company. Lives in Bethesda, Md. (1)

(1) Member of Audit and Compliance Committee (2) Member of Executive Committee (3) Member of Compensation Committee (4) Member of Directors' Affairs Committee (5) Member of Public Policy Committee

Officers (As of March 1, 2004)

Archie W. Dunham, Chairman

J.J. Mulva, President and Chief Executive Officer

William B. Berry, Executive Vice President, Exploration and Production

Jim W. Nokes, Executive Vice President, Refining, Marketing, Supply and Transportation

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

Philip L. Frederickson, Executive Vice President, Commercial

John E. Lowe, Executive Vice President, Planning, Strategy and Corporate Affairs

Stephen F. Gates, Senior Vice President, Legal, and General Counsel

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

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

Steve L. Scheck, General Auditor and Chief Ethics Officer

E. Julia Lambeth, Corporate Secretary

Ben J. Clayton, General Tax Officer

Keith A. Kliewer, Tax Administration Officer

Steve L. Wilson, Assistant Tax Administration Officer

Glenda M. Schwarz, Assistant Controller

C. Douglas Johnson, Assistant Controller

John E. Durbin, Assistant Treasurer

Frances M. Vallejo, Assistant Treasurer

Operational and Functional Organizations

Exploration and Production

Sigmund L. Cornelius, President, Lower 48, Latin America and Midstream

Dodd W. DeCamp, President, Middle East, Russia and Caspian

Ryan M. Lance, President, Asia Pacific

Joseph A. Leone, Vice President, Upstream Technology

James D. McColgin, Vice President, Exploration and Business Development

Henry I. McGee III, President, Europe & Africa

Kevin O. Meyers, President, Alaska

Henry W. Sykes, President, Canada

Refining and Marketing

Stephen R. Barham, President, Transportation

W.C.W. Chiang, President, Strategy, Integration and Specialty Businesses

Gregory J. Goff, President, Europe and Asia Pacific

Mark R. Harper, President, U.S. Marketing

Robert J. Hassler, President, East/Gulf Coast Refining

George W. Paczkowski, Vice President, Downstream Technology

Larry M. Ziemba, President, Central/West Coast Refining

Commercial

C.W. Conway, President, Gas and Power

Andrew J. Kelleher, President, Americas Supply and Trading

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.

Catalyst: Substance that increases the rate of a chemical reaction between other substances.

Coke: A solid carbon product produced by thermal cracking.

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.

Cyclohexane: The cyclic form of hexane used as a raw material in the manufacture of nylon.

Deepwater: Water depth of at least 1,000 feet.

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 in the manufacture of 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.

Fluid Catalytic Cracking Unit: 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.

Midcycle Returns: Midcycle returns are calculated assuming prices of $20 per barrel for West Texas Intermediate crude oil, $3.25 per thousand cubic feet of gas at Henry Hub, and $3.25 per barrel Gulf Coast crack spread for refined products.

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.

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.

S Zorb™ Sulfur Removal Technology (S Zorb): The name for ConocoPhillips' proprietary sulfur removal technologies for gasoline and diesel fuel. The technologies remove sulfur to ultra-low levels while preserving important product characteristics and consuming minimal amounts of hydrogen, a critical element in refining.

Tension-Leg Platform: A semisubmersible drilling platform held in position by multiple cables anchored to the ocean floor.

Three-Dimensional Seismic: Three-dimensional images created by bouncing sound waves off underground rock formations; used by oil companies to determine the best places to drill for hydrocarbons.

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.

Wildcat Drilling: Exploratory drilling performed in an unproven area, far from producing wells.

Stockholder Information

Annual Meeting
ConocoPhillips' annual meeting of stockholders will be held at the following time and place:

May 5, 2004; 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, L.L.C.
P.O. Box 3336
South Hackensack, NJ 07606
Toll-free number: 1-800-356-0066

Information Requests
For information about dividends and certificates, or to request a change of address, stockholders may contact:

Mellon Investor Services, L.L.C.
P.O. Box 3315
South Hackensack, NJ 07606
Toll-free number: 1-800-356-0066
Outside the U.S.: (201) 329-8660
TDD: 1-800-231-5469
Outside the U.S.: (201) 329-8345
Fax: (201) 329-8967
Internet: *www.melloninvestor.com*

Personnel in the following office also can answer investors' questions about the company:

ConocoPhillips Investor Relations
375 Park Avenue, Suite 3702
New York, NY 10152
(212) 207-1996
c.c.reasor@conocophillips.com

Internet: *www.conocophillips.com*
The site includes the Investor Information Center, which features news releases and presentations to securities analysts; copies of ConocoPhillips' Annual Report and Proxy Statement; reports to the U.S. Securities and Exchange Commission; and data on ConocoPhillips' health, safety and environmental performance. Other Web sites with information on topics in this annual report include:

www.cpchem.com
www.defs.com
www.phillips66.com
www.conoco.com
www.76.com

Form 10-K and Annual Reports
Copies of the Annual Report on Form 10-K, as filed with the U.S. Securities and Exchange Commission, are available free by calling (918) 661-3700, making a request on the company's Web site, or writing:

ConocoPhillips - 2003 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 - 2003 Annual Report
B-41 Adams Building
411 South Keeler Ave.
Bartlesville, OK 74004

Principal Offices
600 North Dairy Ashford
Houston, TX 77079

1013 Centre Road
Wilmington, DE 19805-1297

Stock Transfer Offices/Registrars
Mellon Investor Services, L.L.C.
Overpeck Centre
85 Challenger Road
Ridgefield Park, NJ 07660

Compliance and Ethics
For guidance, or to express concerns or ask questions about compliance and ethics issues, call ConocoPhillips' Ethics Helpline toll free: 1-877-327-2272, 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
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600 N. Dairy Ashford
Houston, TX, U.S.A. 77079-1175

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