UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

FORM 10-Q

(Mark One)

[X] QUARTERLY REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934

For the quarterly period ended **June 30, 2004**

OR

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

For the transition period from ____ to ____

Commission file number **000-49987**

ConocoPhillips

(Exact name of registrant as specified in its charter)

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

600 North Dairy Ashford, Houston, TX 77079

(Address of principal executive offices)

281-293-1000

(Registrant's telephone number, including area code)

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. Yes __X__ No____

Indicate by check mark whether the registrant is an accelerated filer (as defined in Rule 12b-2 of the Exchange Act). Yes __X__ No ____

The registrant had 688,750,362 shares of common stock, $.01 par value, outstanding at June 30, 2004.

CONOCOPHILLIPS

TABLE OF CONTENTS

Table of Contents

PART I. FINANCIAL INFORMATION

Item 1. FINANCIAL STATEMENTS

Consolidated Income Statement **ConocoPhillips**

		Millions of Dollars			
		Three Months Ended June 30		Six Months Ended June 30	
		2004	2003**	**2004**	2003**
Revenues					
Sales and other operating revenues*	$	**31,515**	25,321	**61,315**	52,261
Equity in earnings of affiliates		**322**	156	**591**	205
Other income		**49**	97	**197**	176
Total Revenues		**31,886**	25,574	**62,103**	52,642
Costs and Expenses					
Purchased crude oil and products		**20,363**	16,368	**40,098**	34,058
Production and operating expenses		**1,843**	1,848	**3,512**	3,500
Selling, general and administrative expenses		**513**	603	**977**	1,050
Exploration expenses		**163**	142	**306**	258
Depreciation, depletion and amortization		**912**	857	**1,830**	1,716
Property impairments		**20**	146	**51**	174
Taxes other than income taxes*		**4,428**	3,624	**8,542**	7,046
Accretion on discounted liabilities		**41**	35	**77**	68
Interest and debt expense		**159**	218	**304**	457
Foreign currency transaction gains		**(33)**	(26)	**(49)**	(20)
Minority interests		**7**	6	**21**	13
Total Costs and Expenses		**28,416**	23,821	**55,669**	48,320
Income from continuing operations before income taxes and subsidiary equity transactions		**3,470**	1,753	**6,434**	4,322
Gain on subsidiary equity transactions		**—**	28	**—**	28
Income from continuing operations before income taxes		**3,470**	1,781	**6,434**	4,350
Provision for income taxes		**1,457**	685	**2,818**	1,991
Income From Continuing Operations		**2,013**	1,096	**3,616**	2,359
Income from discontinued operations		**62**	91	**75**	144
Income before cumulative effect of changes in accounting principles		**2,075**	1,187	**3,691**	2,503
Cumulative effect of changes in accounting principles		**—**	—	**—**	(95)
Net Income	$	**2,075**	1,187	**3,691**	2,408
Income Per Share of Common Stock					
Basic					
Continuing operations	$	**2.92**	1.62	**5.26**	3.47
Discontinued operations		**.09**	.13	**.11**	.21
Before cumulative effect of changes in accounting principles		**3.01**	1.75	**5.37**	3.68
Cumulative effect of changes in accounting principles		**—**	—	**—**	(.14)
Net Income	$	**3.01**	1.75	**5.37**	3.54
Diluted					
Continuing operations	$	**2.88**	1.60	**5.19**	3.45
Discontinued operations		**.09**	.13	**.11**	.21
Before cumulative effect of changes in accounting principles		**2.97**	1.73	**5.30**	3.66
Cumulative effect of changes in accounting principles		**—**	—	**—**	(.14)
Net Income	$	**2.97**	1.73	**5.30**	3.52
Dividends Paid Per Share of Common Stock	$	**.43**	.40	**.86**	.80
Average Common Shares Outstanding (in thousands)					
Basic		**689,690**	680,028	**687,894**	679,784
Diluted		**699,011**	684,188	**696,764**	683,867
**Includes excise, value added and other similar taxes on petroleum products sales:*	*$*	***4,172***	*3,387*	***7,994***	*6,535*

***Restated for adoption of FIN 46 and reclassified to conform to current year presentation.*
See Notes to Consolidated Financial Statements.

Consolidated Balance Sheet **ConocoPhillips**

		Millions of Dollars	
		June 30 2004	December 31 2003
Assets			
Cash and cash equivalents	$	**804**	490
Accounts and notes receivable (net of allowance of $55 million in 2004 and $43 million in 2003)		**3,851**	3,606
Accounts and notes receivable—related parties		**3,222**	1,399
Inventories		**4,665**	3,957
Prepaid expenses and other current assets		**867**	876
Assets of discontinued operations held for sale		**369**	864
Total Current Assets		**13,778**	11,192
Investments and long-term receivables		**7,296**	7,258
Net properties, plants and equipment		**47,844**	47,428
Goodwill		**15,087**	15,084
Intangibles		**1,104**	1,085
Other assets		**425**	408
Total Assets	$	**85,534**	82,455
Liabilities			
Accounts payable	$	**7,307**	6,598
Accounts payable—related parties		**593**	301
Notes payable and long-term debt due within one year		**1,241**	1,440
Accrued income and other taxes		**2,921**	2,676
Other accruals		**2,277**	2,817
Liabilities of discontinued operations held for sale		**183**	179
Total Current Liabilities		**14,522**	14,011
Long-term debt		**14,378**	16,340
Asset retirement obligations and accrued environmental costs		**3,714**	3,603
Deferred income taxes		**9,226**	8,565
Employee benefit obligations		**2,491**	2,445
Other liabilities and deferred credits		**2,329**	2,283
Total Liabilities		**46,660**	47,247
Minority Interests		**1,048**	842
Common Stockholders' Equity			
Common stock (2,500,000,000 shares authorized at $.01 par value) Issued (2004—713,451,676 shares; 2003—708,085,097 shares)			
Par value		**7**	7
Capital in excess of par		**25,731**	25,361
Compensation and Benefits Trust (CBT) (at cost: 2004—24,701,314 shares and 2003—25,301,314 shares)		**(837)**	(857)
Accumulated other comprehensive income		**849**	821
Unearned employee compensation		**(260)**	(200)
Retained earnings		**12,336**	9,234
Total Common Stockholders' Equity		**37,826**	34,366
Total	$	**85,534**	82,455

See Notes to Consolidated Financial Statements.

Consolidated Statement of Cash Flows **ConocoPhillips**

	Millions of Dollars	
	Six Months Ended June 30	
	2004	2003**
Cash Flows From Operating Activities		
Income from continuing operations	**$ 3,616**	2,359
Adjustments to reconcile income from continuing operations to net cash provided by continuing operations		
Non-working capital adjustments		
Depreciation, depletion and amortization	**1,830**	1,716
Property impairments	**51**	174
Dry hole costs and leasehold impairments	**192**	94
Accretion on discounted liabilities	**77**	68
Deferred taxes	**670**	253
Undistributed equity earnings	**(278)**	(48)
Gain on asset dispositions	**(88)**	(84)
Other	**135**	(38)
Working capital adjustments*		
Increase/(decrease) in aggregate balance of accounts receivable sold	**(675)**	268
Increase in other accounts and notes receivable	**(1,319)**	(237)
Increase in inventories	**(710)**	(283)
Decrease in prepaid expenses and other current assets	**44**	121
Increase in accounts payable	**1,045**	156
Increase/(decrease) in taxes and other accruals	**(263)**	627
Net cash provided by continuing operations	**4,327**	5,146
Net cash provided by discontinued operations	**22**	120
Net Cash Provided by Operating Activities	**4,349**	5,266
Cash Flows From Investing Activities		
Cash consolidated from adoption of FIN 46	**—**	225
Capital expenditures and investments, including dry hole costs	**(3,065)**	(2,865)
Proceeds from asset dispositions	**1,354**	591
Long-term advances to affiliates and other investments	**(35)**	(36)
Net cash used in continuing operations	**(1,746)**	(2,085)
Net cash used in discontinued operations	**(2)**	(31)
Net Cash Used in Investing Activities	**(1,748)**	(2,116)
Cash Flows From Financing Activities		
Issuance of debt	**—**	269
Repayment of debt	**(2,083)**	(2,547)
Issuance of company common stock	**207**	33
Dividends paid on common stock	**(590)**	(543)
Other	**183**	11
Net cash used in continuing operations	**(2,283)**	(2,777)
Net Cash Used in Financing Activities	**(2,283)**	(2,777)
Effect of Exchange Rate Changes on Cash and Cash Equivalents	**(4)**	70
Net Change in Cash and Cash Equivalents	**314**	443
Cash and cash equivalents at beginning of period	**490**	307
Cash and Cash Equivalents at End of Period	**$ 804**	750

**Net of acquisition and disposition of businesses.*
***Restated for adoption of FIN 46 and reclassified to conform to current year presentation.*
See Notes to Consolidated Financial Statements.

Note 1—Interim Financial Information

The financial information for the interim periods presented in the financial statements included in this report is unaudited and includes all known accruals and adjustments that, in the opinion of management, are necessary for a fair presentation of the consolidated financial position of ConocoPhillips and its results of operations and cash flows for such periods. All such adjustments are of a normal and recurring nature. These interim financial statements should be read in conjunction with Management's Discussion and Analysis and the consolidated financial statements and notes included in ConocoPhillips' 2003 Annual Report on Form 10-K. Certain amounts in the 2003 financial statements included in this report on Form 10-Q have been reclassified to conform to ConocoPhillips' 2004 presentation and restated for the adoption of Financial Accounting Standards Board (FASB) Interpretation No. 46, "Consolidation of Variable Interest Entities," (FIN 46).

Note 2—Accounting Policies

Revenue Recognition—Revenues associated with the sale of crude oil, natural gas, natural gas liquids, petroleum and chemical products, and other items are recognized when title passes to the customer, which is when the risk of ownership passes to the purchaser and physical delivery of goods occurs, either immediately or within a fixed delivery schedule that is reasonable and customary in the industry. Revenues include the sales portion of contracts involving physical commodity purchases and sales necessary either to reposition refinery feedstock supply to address location, quality or grade requirements (for example, where we reposition crude oil feedstock supply by entering into a contract with a counterparty to sell crude oil in one location and purchase it in a different location closer to our refinery) or sales related to purchase for resale activity necessary to supply our wholesale commodity businesses (for example, where we enter into a contract with a counterparty to sell refined products or natural gas volumes at one location and purchase similar volumes at another location closer to our wholesale customer). Our commercial group uses commodity derivative contracts (such as futures and options) in various markets to optimize the value of our supply chain and 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. See Note 1—Accounting Policies-Derivative Instruments in our 2003 Form 10-K for additional information on our accounting for, and reporting of, commodity derivative contracts.

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 generally not significant. Revenues associated with royalty fees from licensed technology are recorded based either upon volumes produced by the licensee or upon the successful completion of all substantive performance requirements related to the installation of licensed technology.

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 of a sufficient quantity to justify completion of the find as a producing well. 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. This determination of the success of drilling results, related to areas that do not require a major infrastructure capital expenditure (e.g., a pipeline or an offshore platform), corresponds with the time period of reporting proved oil and gas reserves for the find. Exploratory wells that discover economic reserves that are in areas where a major infrastructure 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 drilling work in the area, remain capitalized as long as the additional exploratory drilling work is under way or firmly planned. In these situations, the well is considered to have found economic reserves if recoverable reserves have been found of a sufficient quantity to justify completion of the find as a producing well, assuming that the major infrastructure capital expenditure had already been made. Once all additional exploratory drilling work has been completed on projects requiring major infrastructure capital expenditures, the economic viability of the overall project is evaluated within one year of the last exploratory well completion. If considered to be economically viable, internal company approvals are then obtained to move the overall project toward a development stage project. If joint-venture partner and government approvals are required before development expenditures can begin, exploratory well costs remain capitalized as long as the company is actively pursuing such approvals and believes such approvals will be obtained. Once all required approvals have been obtained, such projects are moved into development stage status, which corresponds with the time period of reporting proved oil and gas reserves for the find.

Stock-Based Compensation—Effective January 1, 2003, we voluntarily adopted the fair-value accounting method provided under Statement of Financial Accounting Standards (SFAS) No. 123, "Accounting for Stock-Based Compensation." Using the SFAS No. 123 prospective transition method, we apply the fair-value accounting method and recognize 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 (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 provisions of SFAS No. 123 had been applied to all employee stock options granted:

	Millions of Dollars			
	Three Months Ended June 30		Six Months Ended June 30	
	2004	2003	**2004**	2003
Net income, as reported	$ **2,075**	1,187	**3,691**	2,408
Add: Stock-based employee compensation expense included in reported net income, net of related tax effects	**26**	9	**39**	18
Deduct: Total stock-based employee compensation expense determined under fair-value-based method for all awards, net of related tax effects	**28**	16	**44**	34
Pro forma net income	$ **2,073**	1,180	**3,686**	2,392
Earnings per share:				
Basic—as reported	$ **3.01**	1.75	**5.37**	3.54
Basic—pro forma	**3.01**	1.74	**5.36**	3.52
Diluted—as reported	**2.97**	1.73	**5.30**	3.52
Diluted—pro forma	**2.97**	1.72	**5.29**	3.50

Note 3—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. The cumulative effect of the change increased 2003 net income by $145 million (after reduction of income taxes of $21 million).

Consolidation of Variable Interest Entities
In January 2003, the FASB issued 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 December 2003, the FASB issued a revision to FIN 46 to clarify some of the provisions and to exempt certain entities from its guidance. 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.

In the third quarter of 2003, with retroactive application to January 1, 2003, we adopted FIN 46 for variable interest entities (VIEs) involving synthetic leases and certain other financing structures, and accordingly, our financial statements for the second quarter and first six months of 2003 have been restated from amounts previously reported in the financial statements included in our Form 10-Q for the quarter ended June 30, 2003. The cumulative effect of this adoption of FIN 46 decreased 2003 net income $240 million (after an income tax benefit of $145 million). We consolidated all VIEs in which we concluded that we were the primary beneficiary. In addition, we deconsolidated an entity where we determined we were not the primary beneficiary. The provisions of FIN 46, which became effective for periods ending after March 15, 2004, did not change our analysis of any of the entities we consolidated or deconsolidated in 2003.

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 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 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 revenues are 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. At December 31, 2003, we reported these two entities could potentially be VIEs, but that we had been unable to obtain sufficient information to confirm that the entities were VIEs or to determine if we were the primary beneficiary. In the first quarter of 2004, we received the required information related to the entity associated with the first ship and determined that it was a VIE; however, because we are not the primary beneficiary we did not consolidate the entity. With regard to the second ship, we will have a variable interest in the associated entity once the ship is delivered to its owner in 2005. At that time, we will determine if the entity is a VIE, and if we are the primary beneficiary. We continue to account for these agreements as guarantees and contingent liabilities. See Note 11—Guarantees for additional information.

Note 4—Discontinued Operations

During 2003 and the first six months of 2004, we disposed of, or held for sale, certain midstream, refining and marketing assets, which are classified as discontinued operations. We sold our Mobil-branded marketing assets on the East Coast in two separate transactions in the second quarter of 2004. As a result of these and other smaller transactions which closed in the second quarter, we recorded a net after-tax gain of approximately $89 million. Discussions are under way with potential buyers for the remaining marketing assets held for sale, and we expect that the sale of our discontinued operations will be substantially completed by the end of 2004. Based on revised estimates of the fair values of the remaining assets classified as discontinued operations, we recorded an additional charge in the second quarter of 2004 of approximately $12 million before-tax, $8 million after-tax.

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

	Millions of Dollars			
	Three Months Ended June 30		Six Months Ended June 30	
	2004	2003	**2004**	2003
Sales and other operating revenues from discontinued operations	**$ 341**	2,371	**919**	4,553
Income from discontinued operations before-tax	**$ 82**	143	**103**	231
Income tax expense	**20**	52	**28**	87
Income from discontinued operations	**$ 62**	91	**75**	144

The major classes of assets and liabilities of discontinued operations held for sale were as follows:

	Millions of Dollars	
	June 30 2004	December 31 2003
Assets		
Net properties, plants and equipment	**$ 368**	857
Other assets	**1**	7
Assets of discontinued operations	**$ 369**	864
Liabilities		
Deferred income taxes, other liabilities and deferred credits	**$ 183**	179
Liabilities of discontinued operations	**$ 183**	179

Note 5—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, 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.”

Note 6—Inventories

Inventories consisted of the following:

		Millions of Dollars	
		June 30 2004	December 31 2003
Crude oil and petroleum products	**$**	**4,171**	3,467
Materials, supplies and other		**494**	490
	$	**4,665**	3,957

Inventories valued on a last-in, first-out (LIFO) basis totaled $4,013 million and $3,224 million at June 30, 2004, and December 31, 2003, respectively. The remainder of our inventories are valued under various methods, including first-in, first-out and weighted average. The excess of current replacement cost over LIFO cost of inventories was $1,923 million and $1,421 million at June 30, 2004, and December 31, 2003, respectively.

Note 7—Properties, Plants and Equipment

Properties, plants and equipment included the following:

		Millions of Dollars	
		June 30 2004	December 31 2003
Properties, plants and equipment (at cost)	**$**	**64,289**	61,839
Less: accumulated depreciation, depletion and amortization		**16,445**	14,411
	$	**47,844**	47,428

E&P properties, plants and equipment at June 30, 2004, and December 31, 2003, included approximately $9.8 billion and $10.5 billion, respectively, of mineral rights to extract oil and gas, net of accumulated depletion.

Property Impairments—In the second quarter and first six months of 2004, we recorded property impairments related to planned dispositions in our Midstream, E&P and Refining and Marketing (R&M) segments. In the second quarter and first six months of 2003, we recorded property impairments as a result of planned asset dispositions, unsuccessful development drilling results, and Norway tax law changes dealing with the treatment of asset removal costs. The amount of property impairments by segment were:

	Millions of Dollars			
	Three Months Ended June 30		Six Months Ended June 30	
	2004	2003	**2004**	2003
Exploration and Production	**$ 4**	141	**8**	169
Midstream	**16**	—	**36**	—
Refining and Marketing	**—**	—	**7**	—
Corporate and Other	**—**	5	**—**	5
	$ 20	146	**51**	174

Note 8—Restructuring

As a result of the 2002 merger of Conoco Inc. and Phillips Petroleum Company that formed ConocoPhillips, we recognized an estimated restructuring liability for anticipated employee severance payments and incremental pension and medical plan benefit costs associated with workforce reductions, site closings, and Conoco employee relocations. In connection with this program, we recorded accruals in 2002 of $770 million and in 2003, as individual components of the restructuring program were finalized, we recorded an additional $350 million, of which $225 million was accrued in the first six months of 2003, including $179 in the second quarter. Included in the total 2002 and 2003 accruals of $1,120 million was a $290 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. Of the $225 million accrued in the first six months of 2003, $77 million was reflected as a purchase price adjustment in the consolidated financial statements and $148 million was reflected in selling, general and administrative expense and production and operating expense. Included in the total accruals of $225 million was an $83 million expense related to pension and other postretirement benefits. In the first six months of 2004, we recorded additional accruals totaling $19 million, which were reflected in the consolidated financial statements as selling, general and administrative expense and production and operating expense. Included in the total accruals of $19 million was a $4 million expense related to pension and postretirement benefits. A roll-forward of activity during the first six months of 2004 is provided below for the nonpension portion of the accruals, which primarily consists of severance-related benefits to be provided based on agreed upon payment schedules to approximately 3,950 employees worldwide, most of whom are in the United States, as well as other merger-related expenses.

	Millions of Dollars			
		Six Months 2004		
	Reserve at December 31, 2003	Accrual	Payments	Reserve at June 30, 2004
Conoco	$ 83	(12)	(51)	20
Phillips	$ 164	27	(119)	72
Total	$ 247	15	(170)	92

The ending accrual balance at June 30, 2004, is expected to be extinguished within one year, except for $51 million, which is classified as long-term. Approximately 925 employees were terminated during the first six months of 2004 and approximately 3,925 employees have been terminated since the restructuring program was implemented.

Note 9—Debt

At June 30, 2004, 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). The facilities included a $1.5 billion, 364-day revolving credit facility expiring on October 13, 2004; two revolving credit facilities totaling $2 billion expiring in October 2006; and a $500 million five-year facility expiring in October 2008. At June 30, 2004, we had no debt outstanding under these credit facilities, and had no commercial paper outstanding, compared with $709 million at December 31, 2003. The commercial paper is supported 100 percent by the credit facilities and the amount approximates fair value. One of our Norwegian subsidiaries had two $300 million revolving credit facilities that expired in June 2004, which were not renewed.

During the first six months of 2004, we paid off the $1,350 million aggregate principal amount of our 5.90% Notes due 2004 when they matured. In addition, we have given notice to redeem the $1,150 million aggregate principal amount of our 8.5% Notes due 2005 in August of 2004.

Note 10—Contingencies

We are subject to various lawsuits and claims including, but not limited to: personal injury claims; 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 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 also consider unasserted claims in our determination of environmental liabilities and we accrue them in the period that they become both probable and reasonably estimable.

Although liability of those potentially responsible for environmental remediation costs is generally joint and several for federal sites and frequently so for state sites, we are usually only one of many companies cited at a particular site. Due to the joint and several liabilities, we could be responsible for all of the cleanup costs related to any site at which we have been designated as a potentially responsible party. If we were solely responsible, the costs, in some cases, could be material to our, or one of our segments', results of operations, capital resources or liquidity. However, settlements and costs incurred in matters that previously have been resolved have not been material to our results of operations or financial condition. We have been successful to date in sharing cleanup costs with other financially sound companies. Many of the sites at which we are potentially responsible are still under investigation by the EPA or the state agencies concerned. Prior to actual cleanup, those potentially responsible normally assess the site conditions, apportion responsibility and determine the appropriate remediation. In some instances, we may have no liability or may attain a settlement of liability. Where it appears that other potentially responsible parties may be financially unable to bear their proportional share, we consider this inability in estimating our potential liability and 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 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 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. At June 30, 2004, ConocoPhillips' balance sheet included a total environmental accrual of $1,149 million, compared with $1,119 million at December 31, 2003. We expect to incur the majority of these expenditures within the next 30 years. We have not reduced these accruals for possible insurance recoveries. In the future, we may be involved in additional environmental assessments, cleanups and proceedings.

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 ConocoPhillips. In addition, we have performance obligations that are secured by unused letters of credit and various purchase commitments for materials, supplies, services and items of permanent investment incident to the ordinary conduct of business.

Note 11—Guarantees

At June 30, 2004, 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

- In May 2004, the Merey Sweeny, L.P. (MSLP) joint-venture project at the Sweeny refinery in Old Ocean, Texas, achieved completion certification. As a result, the previously disclosed construction completion guarantee related to the debt and bond financing arrangements secured by MSLP expired and the debt became nonrecourse to ConocoPhillips.

- 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 be nonrecourse upon startup and completion certification.

Guarantees of Joint-Venture Debt

- At June 30, 2004, we had guarantees of about $300 million outstanding for our portion of joint-venture debt obligations, which have terms of up to 22 years. Included in these outstanding guarantees was $126 million associated with the Polar Lights Company joint venture in Russia. Payment will be required if the joint venture defaults on its debt obligations.

Other Guarantees

- The MSLP joint-venture project agreement requires the partners in the venture to pay cash calls to cover operating expenses in the event that the venture does not have enough cash to cover operating expenses after setting aside the amount required for debt service over the next 20 years. Although there is no maximum limit stated in the agreement, the intent is to cover short-term cash deficiencies should they occur. Our maximum potential future payments under the agreement are currently estimated to be $100 million, assuming such a shortfall exists at some point in the future due to an extended operational disruption. If such an operational disruption did occur, MSLP has business interruption insurance and would be entitled to insurance proceeds subject to deductibles and certain limits.

- In February 2003, we entered into two agreements establishing separate guarantee facilities for $50 million each for two liquefied natural gas vessels. 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. At the time of the agreement, 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 June 30, 2004, was less than $1 million.

- We have other guarantees totaling $320 million, which consist primarily of dealer and jobber loan guarantees to support our marketing business, a guarantee to fund the short-term cash liquidity deficits of a lubricants joint venture, a guaranteed revenue deficiency payment to a pipeline joint venture, a guarantee supporting a lease assignment on a corporate aircraft, a guarantee associated with a pending lawsuit and guarantees of the lease payment obligations of a joint venture. The carrying amount recorded for these other guarantees, as of June 30, 2004, 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, if the lubricants joint venture has cash liquidity issues, if the pipeline joint venture has revenue below a certain threshold, 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. 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. 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 arrangements.

- During 2003 and the first six months of 2004, 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 terms of these indemnifications vary greatly. The majority of these indemnifications are related to environmental issues, the term is generally indefinite and the maximum amount of future payments is generally unlimited. The carrying amount recorded for these indemnifications, as of June 30, 2004, was $231 million. We amortize the indemnification liability over the relevant time period, if one exists, based on the facts and circumstances surrounding each type of indemnity. In cases where the indemnification term is indefinite, we will reverse the liability when we have information that the liability is essentially relieved or amortize the liability over an appropriate time period as the fair value of our indemnification exposure declines. Although it is reasonably possible 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 was $98 million of environmental accruals for known contamination that is included in asset retirement obligations and accrued environmental costs at June 30, 2004. For additional information about environmental liabilities, see Note 10—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 cost 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 might have to be paid under indemnity obligations stemming from our existing agreements. The carrying amount recorded for these indemnifications, as of June 30, 2004, was $238 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 10-Contingencies.

Note 12—Comprehensive Income

ConocoPhillips' comprehensive income was as follows:

	Millions of Dollars			
	Three Months Ended June 30		Six Months Ended June 30	
	2004	2003	**2004**	2003
Net income	**$ 2,075**	1,187	**3,691**	2,408
After-tax changes in:				
Minimum pension liability adjustment	**—**	—	**(1)**	6
Foreign currency translation adjustments	**44**	121	**44**	258
Unrealized gain (loss) on securities	**(1)**	2	**—**	1
Hedging activities	**1**	—	**1**	4
Equity affiliates:				
Foreign currency translation	**4**	58	**(20)**	90
Derivatives related	**4**	—	**4**	1
	$ 2,127	1,368	**3,719**	2,768

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

	Millions of Dollars	
	June 30 2004	December 31 2003
Minimum pension liability adjustment	**$ (69)**	(68)
Foreign currency translation adjustments	**779**	735
Unrealized gain on securities	**5**	5
Deferred net hedging gain	**3**	2
Equity affiliates:		
Foreign currency translation	**130**	150
Derivatives related	**1**	(3)
	$ 849	821

Note 13—Supplemental Cash Flow Information

	Millions of Dollars	
	Six Months Ended June 30	
	2004	2003
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 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
Cash Payments		
Interest	**$ 318**	464
Income taxes	**1,825**	1,331

Note 14—Sales of Receivables

At June 30, 2004, certain credit card and trade receivables had been sold to a Qualifying Special Purpose Entity (QSPE) in a revolving-period securitization arrangement. This arrangement provides for us to sell, and the QSPE to purchase, certain receivables, and for the QSPE to then issue beneficial interests of up to $1.2 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 QSPE because it meets 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.

At June 30, 2004, and December 31, 2003, the QSPE had issued beneficial interests to the bank-sponsored entities of $525 million and $1.2 billion, respectively. The receivables transferred to the QSPE met the isolation and other requirements of SFAS No. 140 to be accounted for as sales and were accounted for accordingly.

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 $2.9 billion at June 30, 2004, and $1.3 billion at December 31, 2003. We also retain servicing responsibility related to the sold receivables, which gives us certain rights and abilities, the fair value of which approximates the fair value of the liability incurred for continuing to service the receivables. The carrying value of our subordinated beneficial interests in the QSPE approximates fair market value due to the very short term of the underlying assets, which makes fair value stress testing for disclosure purposes unnecessary.

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

	Millions of Dollars	
	2004	2003
Receivables sold at beginning of year	**$ 1,200**	1,323
New receivables sold	**5,025**	13,849
Cash collections remitted	**(5,700)**	(13,751)
Receivables sold at June 30	**$ 525**	1,421
Discounts and other fees paid on revolving balances	**$ 4**	11

The decrease in cash flow activity in 2004 was primarily due to reductions in the average level of beneficial interests issued to the bank-sponsored entities.

At December 31, 2003, we had sold $226 million of receivables under factoring arrangements. We retained servicing responsibility related to those sold receivables, which gave us certain benefits, the fair value of which approximated the fair value of the liability incurred for continuing to service the receivables. At June 30, 2004, we had no receivables outstanding under similar arrangements.

Note 15—Employee Benefit Plans

Pension and Postretirement Plans

	Millions of Dollars					
	Pension Benefits				Other Benefits	
Three Months Ended	June 30				June 30	
	2004		2003		**2004**	2003
	U.S.	**Int'l.**	U.S.	Int'l.		
Components of Net Periodic Benefit Cost						
Service cost	**$ 38**	**18**	33	14	**6**	4
Interest cost	**43**	**27**	49	20	**14**	14
Expected return on plan assets	**(26)**	**(22)**	(23)	(18)	**—**	—
Amortization of prior service cost	**1**	**1**	1	1	**5**	4
Recognized net actuarial loss	**13**	**10**	18	4	**3**	2
Net periodic benefit costs	**$ 69**	**34**	78	21	**28**	24

Six Months Ended	Millions of Dollars					
	Pension Benefits				Other Benefits	
	June 30				June 30	
	2004		2003		**2004**	2003
	U.S.	**Int'l.**	U.S.	Int'l.		
Components of Net Periodic Benefit Cost						
Service cost	**$ 75**	**34**	66	26	**11**	8
Interest cost	**87**	**55**	98	36	**29**	29
Expected return on plan assets	**(52)**	**(45)**	(45)	(32)	**—**	—
Amortization of prior service cost	**2**	**3**	2	2	**10**	9
Recognized net actuarial loss	**26**	**20**	35	7	**5**	3
Net periodic benefit costs	**$138**	**67**	156	39	**55**	49

We recognized pension settlement losses of $6 million and $82 million in the first six months of 2004 and 2003, respectively, due to high levels of lump-sum elections by new retirees in certain plans. Of these amounts, $2 million and $73 million were recognized in the second quarters of 2004 and 2003, respectively.

In 2003, we elected to defer financial recognition of the Medicare Prescription Drug, Improvement and Modernization Act of 2003 pending final guidance from the FASB. This deferral was 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." Under provisions of the Act, companies that provide prescription drug coverage to retirees over age 65 will be entitled to a government subsidy beginning in 2006 if the benefits provided under the company plan are at least actuarially equivalent to those that will otherwise be offered by the government. Final accounting guidance was issued in May 2004 with FASB Staff Position No. FAS 106-2, "Accounting and Disclosure Requirements Related to the Medicare Prescription Drug, Improvement and Modernization Act of 2003," which requires that we reflect the effect of the Act in our third quarter 2004 financial statements. We continue to evaluate the impact of the legislation on our benefit plan design and accounting.

In our 2003 Annual Report on Form 10-K, we disclosed that our 2004 contributions were expected to be approximately $400 million to our domestic qualified and non-qualified benefit plans and $100 million to our international qualified and non-qualified benefit plans. We presently anticipate 2004 contributions to be $425 million to our domestic plans and $125 million to our international plans.

Table of Contents

Note 16—Related Party Transactions

Significant transactions with related parties were:

	Millions of Dollars			
	Three Months Ended June 30		Six Months Ended June 30	
	2004	2003	**2004**	2003
Operating revenues (a)	**$ 1,258**	922	**2,343**	2,009
Purchases (b)	**990**	803	**1,939**	1,705
Operating expenses and selling, general and administrative expenses (c)	**198**	136	**334**	260
Net interest income (d)	**8**	5	**15**	11

(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, and Hamaca Holding LLC 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 upgraded 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 and a price upgrade to MSLP for heavy crude processing.

(c) We pay processing fees to various affiliates. Additionally, we pay crude oil transportation fees to pipeline equity companies, and commissions to the receivables securitization QSPE.

(d) We pay and/or receive interest to/from various affiliates including the receivables securitization QSPE.

Elimination of our equity percentage share of profit or loss on the above transactions was not material.

Note 17—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) Exploration and Production (E&P)—This segment primarily explores for and produces crude oil, natural gas and natural gas liquids on a worldwide basis. At June 30, 2004, E&P was producing in the United States, Norway, the United Kingdom, Canada, Nigeria, Venezuela, offshore Timor Leste in the Timor Sea, Australia, 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) Refining and Marketing (R&M)—This segment purchases, refines, markets and transports crude oil and petroleum products, mainly in the United States, Europe and Asia. At June 30, 2004, 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, discontinued operations, restructuring charges resulting from the merger, 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. Intersegment sales are recorded at prices that approximate market value.

Table of Contents

Analysis of Results by Operating Segment

	Millions of Dollars			
	Three Months Ended June 30		Six Months Ended June 30	
	2004	2003	**2004**	2003
Sales and Other Operating Revenues				
E&P				
United States	**$ 5,646**	5,113	**11,213**	9,851
International	**3,668**	3,133	**7,707**	6,438
Intersegment eliminations-U.S.	**(697)**	(587)	**(1,359)**	(1,269)
Intersegment eliminations-international	**(1,021)**	(754)	**(1,959)**	(1,551)
E&P	**7,596**	6,905	**15,602**	13,469
Midstream				
Total sales	**700**	889	**1,939**	2,509
Intersegment eliminations	**(184)**	(312)	**(537)**	(688)
Midstream	**516**	577	**1,402**	1,821
R&M				
United States	**17,391**	13,319	**32,818**	27,728
International	**6,065**	4,586	**11,591**	9,385
Intersegment eliminations-U.S.	**(97)**	(111)	**(192)**	(238)
Intersegment eliminations-international	**—**	(1)	**(1)**	(12)
R&M	**23,359**	17,793	**44,216**	36,863
Chemicals	**3**	3	**7**	6
Emerging Businesses	**39**	38	**85**	94
Corporate and Other	**2**	5	**3**	8
Consolidated Sales and Other Operating Revenues	**$ 31,515**	25,321	**61,315**	52,261
Net Income (Loss)				
E&P				
United States	**$ 671**	517	**1,306**	1,337
International	**683**	560	**1,305**	1,007
Total E&P	**1,354**	1,077	**2,611**	2,344
Midstream	**42**	25	**97**	56
R&M				
United States	**734**	248	**1,137**	398
International	**84**	73	**145**	187
Total R&M	**818**	321	**1,282**	585
Chemicals	**46**	12	**85**	(11)
Emerging Businesses	**(29)**	(23)	**(51)**	(57)
Corporate and Other	**(156)**	(225)	**(333)**	(509)
Consolidated Net Income	**$ 2,075**	1,187	**3,691**	2,408

	Millions of Dollars	
	June 30 2004	December 31 2003
Total Assets		
E&P		
United States	**$ 15,486**	15,262
International	**23,326**	22,458
Goodwill	**11,184**	11,184
Total E&P	**49,996**	48,904
Midstream	**1,323**	1,736
R&M		
United States	**19,357**	17,172
International	**5,268**	5,020
Goodwill	**3,903**	3,900
Total R&M	**28,528**	26,092
Chemicals	**2,151**	2,094
Emerging Businesses	**916**	843
Corporate and Other	**2,620**	2,786
Consolidated Total Assets	**$ 85,534**	82,455

Note 18—Income Taxes

Our effective tax rates for the second quarter and first six months of 2004 were 42 percent and 44 percent, respectively, compared with 38 percent and 46 percent for the same periods a year ago. Tax law changes in certain international jurisdictions occurred during the second quarters of both 2003 and 2004. The benefit of the 2003 changes was greater than the 2004 changes, resulting in the lower effective tax rate in the second quarter of 2003, when compared with the corresponding period in 2004. The reduction in the effective tax rate for the first six months of 2004, versus the same period in 2003, was mainly due to the impact of a higher proportion of income in lower tax rate jurisdictions, which more than offset the effect of international tax law changes. The effective tax rate in excess of the domestic federal statutory rate of 35 percent was primarily due to foreign taxes in excess of the domestic federal statutory rate.

Note 19—Minority Interests

The minority limited partner in Conoco Corporate Holdings L.P., a limited-life entity, was entitled to a cumulative annual 7.86 percent priority return on its investment. That net minority interest was $141 million at June 30, 2004, and December 31, 2003. On July 8, 2004, we retired the minority interest in Conoco Corporate Holdings L.P.

Note 20—New Accounting Standards

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 the Standard effective December 2003, except for certain provisions regarding disclosure of information about estimated future benefit payments, which are not required until the fourth quarter of 2004.

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. The Statement, already effective for contracts created or modified after May 31, 2003, was originally intended to become effective July 1, 2003, for all contracts existing at May 31, 2003. However, on November 7, 2003, the FASB issued an indefinite deferral of certain provisions of SFAS No. 150. We continue to monitor and assess the FASB’s modifications of SFAS No. 150, but do not anticipate any material impact to our financial statements.

In April 2004, the FASB issued FASB Staff Position Nos. FAS 141-1 and FAS 142-1, which amended SFAS No. 141, “Business Combinations,” and SFAS No. 142, “Goodwill and Other Intangible Assets,” to remove mineral rights as an example of an intangible asset. See Note 7—Properties, Plants and Equipment for additional information.

In January 2004 and May 2004, the FASB issued FASB Staff Position Nos. 106-1 and 106-2, respectively, regarding accounting and disclosure requirements related to the Medicare Prescription Drug, Improvement and Modernization Act of 2003. See Note 15—Employee Benefit Plans for additional information.

In March 2004, the EITF reached a consensus on Issue 03-06, “Participating Securities and the Two-Class Method under FASB Statement No. 128, Earnings per Share.” The EITF explained how to determine whether a security should be considered a “participating security” for purposes of computing earnings per share and how earnings should be allocated to a participating security when using the two-class method for computing basic earnings per share. The adoption of this standard in the second quarter of 2004 did not have a material effect on our earnings per share calculations for the periods presented.

Supplementary Information—Condensed Consolidating Financial Information

We have various cross guarantees among ConocoPhillips, ConocoPhillips Holding Company, and ConocoPhillips Company. ConocoPhillips Company is wholly owned by ConocoPhillips Holding Company, which is wholly owned by ConocoPhillips. ConocoPhillips and ConocoPhillips Holding Company have fully and unconditionally guaranteed the payment obligations of ConocoPhillips Company with respect to its publicly held debt securities. Similarly, ConocoPhillips and ConocoPhillips Company have fully and unconditionally guaranteed the payment obligations of ConocoPhillips Holding Company with respect to its publicly held debt securities. In addition, ConocoPhillips Company and ConocoPhillips Holding Company have fully and unconditionally guaranteed the payment obligations of ConocoPhillips with respect to its publicly held debt securities. All guarantees are joint and several. The following condensed consolidating financial information presents the results of operations, financial position and cash flows for:

- ConocoPhillips, ConocoPhillips Holding Company, and ConocoPhillips Company (in each case, reflecting investments in subsidiaries utilizing the equity method of accounting);
- All other non-guarantor subsidiaries of ConocoPhillips Holding Company and ConocoPhillips Company; and
- The consolidating adjustments necessary to present ConocoPhillips' results on a consolidated basis.

This condensed consolidating financial information should be read in conjunction with the accompanying consolidated financial statements and notes. Certain amounts in 2003 have been restated for the adoption of FIN 46 and reclassified to conform to the current year presentation.

Income Statement	Millions of Dollars Three Months Ended June 30, 2004 ConocoPhillips	ConocoPhillips Holding Company	ConocoPhillips Company	All Other Subsidiaries	Consolidating Adjustments	Total Consolidated
Revenues						
Sales and other operating revenues	$ —	—	21,046	10,469	—	31,515
Equity in earnings of affiliates	2,011	1,959	1,261	190	(5,099)	322
Other income	—	—	6	43	—	49
Intercompany revenues	21	156	462	1,500	(2,139)	—
Total Revenues	2,032	2,115	22,775	12,202	(7,238)	31,886
Costs and Expenses						
Purchased crude oil and products	—	—	16,898	5,336	(1,871)	20,363
Production and operating expenses	—	1	1,000	852	(10)	1,843
Selling, general and administrative expenses	2	—	348	165	(2)	513
Exploration expenses	—	—	32	131	—	163
Depreciation, depletion and amortization	—	—	277	635	—	912
Property impairments	—	—	—	20	—	20
Taxes other than income taxes	—	—	1,570	2,858	—	4,428
Accretion on discounted liabilities	—	—	9	32	—	41
Interest and debt expense	22	78	295	20	(256)	159
Foreign currency transaction losses (gains)	—	—	7	(40)	—	(33)
Minority interests	—	—	—	7	—	7
Total Costs and Expenses	24	79	20,436	10,016	(2,139)	28,416
Income from continuing operations before income taxes and subsidiary equity transactions	2,008	2,036	2,339	2,186	(5,099)	3,470
Gain on subsidiary equity transactions	—	—	—	—	—	—
Income from continuing operations before income taxes	2,008	2,036	2,339	2,186	(5,099)	3,470
Provision for income taxes	(5)	25	411	1,026	—	1,457
Income from continuing operations	2,013	2,011	1,928	1,160	(5,099)	2,013
Income from discontinued operations	62	62	62	31	(155)	62
Income before cumulative effect of changes in accounting principles	2,075	2,073	1,990	1,191	(5,254)	2,075
Cumulative effect of changes in accounting principles	—	—	—	—	—	—
Net Income	$ 2,075	2,073	1,990	1,191	(5,254)	2,075

Table of Contents

Income Statement	Millions of Dollars Three Months Ended June 30, 2003 ConocoPhillips	ConocoPhillips Holding Company	ConocoPhillips Company	All Other Subsidiaries	Consolidating Adjustments	Total Consolidated
Revenues						
Sales and other operating revenues	$ —	—	15,667	9,654	—	25,321
Equity in earnings of affiliates	1,089	1,050	1,134	139	(3,256)	156
Other income	—	—	42	55	—	97
Intercompany revenues	39	150	807	1,244	(2,240)	—
Total Revenues	1,128	1,200	17,650	11,092	(5,496)	25,574
Costs and Expenses						
Purchased crude oil and products	—	—	13,837	4,417	(1,886)	16,368
Production and operating expenses	—	—	1,025	866	(43)	1,848
Selling, general and administrative expenses	4	—	382	224	(7)	603
Exploration expenses	—	—	28	114	—	142
Depreciation, depletion and amortization	—	—	292	565	—	857
Property impairments	—	—	26	120	—	146
Taxes other than income taxes	—	—	615	3,009	—	3,624
Accretion on discounted liabilities	—	—	6	29	—	35
Interest and debt expense	34	90	340	58	(304)	218
Foreign currency transaction losses (gains)	—	—	(9)	(17)	—	(26)
Minority interests	—	—	—	6	—	6
Total Costs and Expenses	38	90	16,542	9,391	(2,240)	23,821
Income from continuing operations before income taxes and subsidiary equity transactions	1,090	1,110	1,108	1,701	(3,256)	1,753
Gain on subsidiary equity transactions	—	—	—	28	—	28
Income from continuing operations before income taxes	1,090	1,110	1,108	1,729	(3,256)	1,781
Provision for income taxes	(6)	21	79	591	—	685
Income from continuing operations	1,096	1,089	1,029	1,138	(3,256)	1,096
Income from discontinued operations	91	91	91	49	(231)	91
Income before cumulative effect of changes in accounting principles	1,187	1,180	1,120	1,187	(3,487)	1,187
Cumulative effect of changes in accounting principles	—	—	—	—	—	—
Net Income	$ 1,187	1,180	1,120	1,187	(3,487)	1,187

Income Statement	ConocoPhillips	ConocoPhillips Holding Company	ConocoPhillips Company	All Other Subsidiaries	Consolidating Adjustments	Total Consolidated
	Millions of Dollars					
	Six Months Ended June 30, 2004					
Revenues						
Sales and other operating revenues	$ —	—	40,460	20,855	—	61,315
Equity in earnings of affiliates	3,611	3,507	2,406	405	(9,338)	591
Other income	—	—	(1)	198	—	197
Intercompany revenues	44	286	846	2,892	(4,068)	—
Total Revenues	3,655	3,793	43,711	24,350	(13,406)	62,103
Costs and Expenses						
Purchased crude oil and products	—	—	33,002	10,659	(3,563)	40,098
Production and operating expenses	—	1	1,891	1,642	(22)	3,512
Selling, general and administrative expenses	4	—	648	334	(9)	977
Exploration expenses	—	—	50	256	—	306
Depreciation, depletion and amortization	—	—	517	1,313	—	1,830
Property impairments	—	—	7	44	—	51
Taxes other than income taxes	—	—	2,921	5,621	—	8,542
Accretion on discounted liabilities	—	—	19	58	—	77
Interest and debt expense	44	128	582	24	(474)	304
Foreign currency transaction losses (gains)	—	—	1	(50)	—	(49)
Minority interests	—	—	—	21	—	21
Total Costs and Expenses	48	129	39,638	19,922	(4,068)	55,669
Income from continuing operations before income taxes and subsidiary equity transactions	3,607	3,664	4,073	4,428	(9,338)	6,434
Gain on subsidiary equity transactions	—	—	—	—	—	—
Income from continuing operations before income taxes	3,607	3,664	4,073	4,428	(9,338)	6,434
Provision for income taxes	(9)	53	607	2,167	—	2,818
Income from continuing operations	3,616	3,611	3,466	2,261	(9,338)	3,616
Income from discontinued operations	75	75	75	90	(240)	75
Income before cumulative effect of changes in accounting principles	3,691	3,686	3,541	2,351	(9,578)	3,691
Cumulative effect of changes in accounting principles	—	—	—	—	—	—
Net Income	$ 3,691	3,686	3,541	2,351	(9,578)	3,691

Table of Contents

Income Statement	ConocoPhillips	ConocoPhillips Holding Company	ConocoPhillips Company	All Other Subsidiaries	Consolidating Adjustments	Total Consolidated
	Millions of Dollars					
	Six Months Ended June 30, 2003					
Revenues						
Sales and other operating revenues	$ —	—	32,754	19,507	—	52,261
Equity in earnings of affiliates	2,347	2,272	2,102	220	(6,736)	205
Other income	—	—	84	92	—	176
Intercompany revenues	75	300	1,776	2,744	(4,895)	—
Total Revenues	2,422	2,572	36,716	22,563	(11,631)	52,642
Costs and Expenses						
Purchased crude oil and products	—	—	28,574	9,674	(4,190)	34,058
Production and operating expenses	—	—	1,951	1,638	(89)	3,500
Selling, general and administrative expenses	5	—	700	354	(9)	1,050
Exploration expenses	—	—	59	199	—	258
Depreciation, depletion and amortization	—	—	575	1,141	—	1,716
Property impairments	—	—	26	148	—	174
Taxes other than income taxes	—	—	1,697	5,349	—	7,046
Accretion on discounted liabilities	—	—	13	55	—	68
Interest and debt expense	65	184	679	136	(607)	457
Foreign currency transaction losses (gains)	—	—	(17)	(3)	—	(20)
Minority interests	—	—	—	13	—	13
Total Costs and Expenses	70	184	34,257	18,704	(4,895)	48,320
Income from continuing operations before income taxes and subsidiary equity transactions	2,352	2,388	2,459	3,859	(6,736)	4,322
Gain on subsidiary equity transactions	—	—	—	28	—	28
Income from continuing operations before income taxes	2,352	2,388	2,459	3,887	(6,736)	4,350
Provision for income taxes	(7)	41	222	1,735	—	1,991
Income from continuing operations	2,359	2,347	2,237	2,152	(6,736)	2,359
Income from discontinued operations	144	144	144	68	(356)	144
Income before cumulative effect of changes in accounting principles	2,503	2,491	2,381	2,220	(7,092)	2,503
Cumulative effect of changes in accounting principles	(95)	(95)	(95)	(255)	445	(95)
Net Income	$ 2,408	2,396	2,286	1,965	(6,647)	2,408

Table of Contents

Balance Sheet						
	Millions of Dollars					
	At June 30, 2004					
	ConocoPhillips	ConocoPhillips Holding Company	ConocoPhillips Company	All Other Subsidiaries	Consolidating Adjustments	Total Consolidated
Assets						
Cash and cash equivalents	$ —	—	418	386	—	804
Accounts and notes receivable	1,560	857	13,210	13,900	(22,454)	7,073
Inventories	—	—	3,331	1,334	—	4,665
Prepaid expenses and other current assets	24	23	378	442	—	867
Assets of discontinued operations held for sale	—	—	277	92	—	369
Total Current Assets	1,584	880	17,614	16,154	(22,454)	13,778
Investments and long-term receivables	31,964	39,722	37,909	15,734	(118,033)	7,296
Net properties, plants and equipment	—	—	16,100	31,744	—	47,844
Goodwill	—	—	15,087	—	—	15,087
Intangibles	—	—	795	309	—	1,104
Other assets	15	—	119	291	—	425
Total	$ 33,563	40,602	87,624	64,232	(140,487)	85,534
Liabilities and Stockholders' Equity						
Accounts payable	$ 4	8	19,689	10,653	(22,454)	7,900
Notes payable and long-term debt due within one year	—	—	1,221	20	—	1,241
Accrued income and other taxes	(2)	64	830	2,029	—	2,921
Other accruals	20	42	1,020	1,195	—	2,277
Liabilities of discontinued operations held for sale	—	—	163	20	—	183
Total Current Liabilities	22	114	22,923	13,917	(22,454)	14,522
Long-term debt	1,976	2,893	5,239	4,270	—	14,378
Asset retirement obligations and accrued environmental costs	—	—	970	2,744	—	3,714
Deferred income taxes	(7)	(85)	2,891	6,435	(8)	9,226
Employee benefit obligations	—	—	1,841	650	—	2,491
Other liabilities and deferred credits	34	6,303	24,561	21,665	(50,234)	2,329
Total Liabilities	2,025	9,225	58,425	49,681	(72,696)	46,660
Minority interests	—	(12)	5	1,055	—	1,048
Retained earnings	5,797	5,151	12,240	10,812	(21,664)	12,336
Other stockholders' equity	25,741	26,238	16,954	2,684	(46,127)	25,490
Total	$ 33,563	40,602	87,624	64,232	(140,487)	85,534

Balance Sheet	Millions of Dollars At December 31, 2003 ConocoPhillips	ConocoPhillips Holding Company	ConocoPhillips Company	All Other Subsidiaries	Consolidating Adjustments	Total Consolidated
Assets						
Cash and cash equivalents	$ —	—	268	222	—	490
Accounts and notes receivable	1,185	564	10,893	13,951	(21,588)	5,005
Inventories	—	—	2,579	1,378	—	3,957
Prepaid expenses and other current assets	8	7	388	473	—	876
Assets of discontinued operations held for sale	—	—	591	273	—	864
Total Current Assets	1,193	571	14,719	16,297	(21,588)	11,192
Investments and long-term receivables	29,640	37,358	37,656	17,168	(114,564)	7,258
Net properties, plants and equipment	—	—	16,495	30,933	—	47,428
Goodwill	—	—	15,046	38	—	15,084
Intangibles	—	—	743	342	—	1,085
Other assets	20	—	92	296	—	408
Total Assets	$ 30,853	37,929	84,751	65,074	(136,152)	82,455
Liabilities and Stockholders' Equity						
Accounts payable	$ —	2	19,371	9,114	(21,588)	6,899
Notes payable and long-term debt due within one year	—	1,350	70	20	—	1,440
Accrued income and other taxes	38	96	625	1,917	—	2,676
Other accruals	20	45	1,227	1,525	—	2,817
Liabilities of discontinued operations held for sale	—	—	179	—	—	179
Total Current Liabilities	58	1,493	21,472	12,576	(21,588)	14,011
Long-term debt	2,704	2,938	6,394	4,304	—	16,340
Asset retirement obligations and accrued environmental costs	—	—	930	2,673	—	3,603
Deferred income taxes	—	(33)	2,575	6,031	(8)	8,565
Employee benefit obligations	—	—	1,828	617	—	2,445
Other liabilities and deferred credits	—	5,961	25,290	21,460	(50,428)	2,283
Total Liabilities	2,762	10,359	58,489	47,661	(72,024)	47,247
Minority interests	—	(12)	5	849	—	842
Retained earnings	2,695	1,399	9,418	10,546	(14,824)	9,234
Other stockholders' equity	25,396	26,183	16,839	6,018	(49,304)	25,132
Total	$ 30,853	37,929	84,751	65,074	(136,152)	82,455

Statement of Cash Flows	Millions of Dollars Six Months Ended June 30, 2004 ConocoPhillips	ConocoPhillips Holding Company	ConocoPhillips Company	All Other Subsidiaries	Consolidating Adjustments	Total Consolidated
Cash Flows From Operating Activities						
Net cash provided by (used in) continuing operations	$ (267)	(247)	2,763	2,929	(851)	4,327
Net cash provided by (used in) discontinued operations	—	—	(319)	341	—	22
Net Cash Provided by (Used in) Operating Activities	(267)	(247)	2,444	3,270	(851)	4,349
Cash Flows From Investing Activities						
Cash consolidated from adoption of FIN 46	—	—	—	—	—	—
Capital expenditures and investments, including dry holes	—	—	(707)	(2,464)	106	(3,065)
Proceeds from asset dispositions	—	—	1,097	458	(201)	1,354
Long-term advances to affiliates and other investments	1,359	1,287	(1,376)	(404)	(901)	(35)
Net cash used in continuing operations	1,359	1,287	(986)	(2,410)	(996)	(1,746)
Net cash provided by (used in) discontinued operations	—	—	(2)	—	—	(2)
Net Cash Used in Investing Activities	1,359	1,287	(988)	(2,410)	(996)	(1,748)
Cash Flows From Financing Activities						
Issuance of debt	—	1,668	—	77	(1,745)	—
Repayment of debt	(709)	(2,708)	(1,301)	(11)	2,646	(2,083)
Issuance of company common stock	207	—	—	—	—	207
Dividends paid on common stock	(590)	—	—	(851)	851	(590)
Other	—	—	—	88	95	183
Net Cash Provided by (Used in) Financing Activities	(1,092)	(1,040)	(1,301)	(697)	1,847	(2,283)
Effect of Exchange Rate Changes on Cash and Cash Equivalents	—	—	(5)	1	—	(4)
Net Change in Cash and Cash Equivalents	—	—	150	164	—	314
Cash and cash equivalents at beginning of year	—	—	268	222	—	490
Cash and Cash Equivalents at End of Period	$ —	—	418	386	—	804

Table of Contents

Statement of Cash Flows	Millions of Dollars Six Months Ended June 30, 2003 ConocoPhillips	ConocoPhillips Holding Company	ConocoPhillips Company	All Other Subsidiaries	Consolidating Adjustments	Total Consolidated
Cash Flows From Operating Activities						
Net cash provided by (used in) continuing operations	$ 3,026	(770)	1,378	4,627	(3,115)	5,146
Net cash provided by discontinued operations	—	—	85	35	—	120
Net Cash Provided by (Used in) Operating Activities	3,026	(770)	1,463	4,662	(3,115)	5,266
Cash Flows From Investing Activities						
Cash consolidated from adoption of FIN 46	—	—	—	225	—	225
Capital expenditures and investments, including dry holes	—	(44)	(1,182)	(2,192)	553	(2,865)
Proceeds from asset dispositions	—	—	57	534	—	591
Long-term advances to affiliates and other investments	(1,799)	30	(7,656)	(2,377)	11,766	(36)
Net cash used in continuing operations	(1,799)	(14)	(8,781)	(3,810)	12,319	(2,085)
Net cash used in discontinued operations	—	—	(15)	(16)	—	(31)
Net Cash Used in Investing Activities	(1,799)	(14)	(8,796)	(3,826)	12,319	(2,116)
Cash Flows From Financing Activities						
Issuance of debt	—	2,073	9,087	875	(11,766)	269
Repayment of debt	(717)	(500)	(784)	(546)	—	(2,547)
Issuance of company common stock	33	—	—	—	—	33
Redemption of preferred stock of subsidiary	—	—	—	—	—	—
Dividends paid on common stock	(543)	(789)	(789)	(1,537)	3,115	(543)
Other	—	—	(123)	687	(553)	11
Net Cash Provided by (Used in) Financing Activities	(1,227)	784	7,391	(521)	(9,204)	(2,777)
Effect of Exchange Rate Changes on Cash and Cash Equivalents	—	—	4	66	—	70
Net Change in Cash and Cash Equivalents	—	—	62	381	—	443
Cash and cash equivalents at beginning of year	—	—	116	191	—	307
Cash and Cash Equivalents at End of Period	$ —	—	178	572	—	750

Item 2. MANAGEMENT’S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

Management’s Discussion and Analysis contains forward-looking statements including, without limitation, statements relating to our plans, strategies, objectives, expectations, and intentions, that are made pursuant to the “safe harbor” provisions of the Private Securities Litigation Reform Act of 1995. The words “intends,” “believes,” “expects,” “plans,” “scheduled,” “anticipates,” “estimates,” and similar expressions identify forward-looking statements. We do not undertake to update, revise or correct any of the forward-looking information. Readers are cautioned that such forward-looking statements should be read in conjunction with the 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 62.

RESULTS OF OPERATIONS

Unless otherwise indicated, discussion of results for the three- and six-month periods ending June 30, 2004, is based on a comparison with the corresponding periods of 2003.

Business Environment and Executive Overview

Favorable market conditions resulted in a strong financial performance in the second quarter of 2004. Net income in the second quarter of 2004 was $2,075 million, while cash from operations totaled $2,276 million. This, combined with proceeds from asset sales of $905 million, allowed us to fund our capital expenditures of $1,584 million, pay common stock dividends of $296 million, and reduce our debt by $1,490 million. For the first six months of 2004, net income was $3,691 million, cash from operations totaled $4,349 million, and proceeds from asset sales amounted to $1,354 million. Common stock dividends paid were $590 million and debt reduction totaled $2,161 million.

Our Exploration and Production segment had net income of $1,354 million in the second quarter of 2004, compared with $1,257 million in the first quarter of 2004 and $1,077 million in the second quarter of 2003. Industry crude oil prices continued to rise in the second quarter of 2004, averaging about $38 per barrel for West Texas Intermediate. The upward trend was primarily due to rising global consumption associated with the economic recovery, continued sabotage of Iraqi oil export capabilities, risk of oil supply disruptions in other producing countries, and strong U.S. refinery crude oil throughput demand. Industry U.S. natural gas prices also continued to rise in the second quarter of 2004, averaging about $6.00 per thousand cubic feet for Henry Hub. Despite adequate natural gas inventory levels, natural gas prices trended upward during the second quarter due to supply availability concerns, the economic recovery causing industrial natural gas demand to rebound, and high crude oil prices limiting consumers’ incentive to switch fuel away from natural gas.

Our Refining and Marketing segment had net income of $818 million in the second quarter of 2004, compared with $464 million in the first quarter of 2004 and $321 million in the second quarter of 2003. Industry U.S. refining margins rose to high levels in the second quarter of 2004, primarily due to very strong U.S. gasoline demand, low gasoline inventories early in the quarter, and concern about supply availability due to more stringent gasoline specifications and the implementation of methyl tertiary-butyl ether (MTBE) bans in several Northeast states. Industry U.S. marketing margins improved in the second quarter of 2004 from weak first-quarter levels, which were caused when wholesale and retail prices did not rise as rapidly as gasoline spot market prices (which represents marketing’s cost of supply). In the latter part of the second quarter, spot gasoline prices declined faster than wholesale and retail prices, thereby improving marketing margins.

At June 30, 2004, our debt-to-capital ratio was 29 percent, compared with 32 percent at March 31, 2004, and 34 percent at December 31, 2003. We have made a priority of using funds available after paying dividends and capital spending to reduce debt.

Consolidated Results

	Millions of Dollars			
	Three Months Ended June 30		Six Months Ended June 30	
	2004	2003	**2004**	2003
Income from continuing operations	**$ 2,013**	1,096	**3,616**	2,359
Income from discontinued operations	**62**	91	**75**	144
Cumulative effect of accounting changes	**—**	—	**—**	(95)
Net income	**$ 2,075**	1,187	**3,691**	2,408

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

	Millions of Dollars			
	Three Months Ended June 30		Six Months Ended June 30	
	2004	2003	**2004**	2003
Exploration and Production (E&P)	**$ 1,354**	1,077	**2,611**	2,344
Midstream	**42**	25	**97**	56
Refining and Marketing (R&M)	**818**	321	**1,282**	585
Chemicals	**46**	12	**85**	(11)
Emerging Businesses	**(29)**	(23)	**(51)**	(57)
Corporate and Other	**(156)**	(225)	**(333)**	(509)
Net income	**$ 2,075**	1,187	**3,691**	2,408

Net income was $2,075 million in the second quarter of 2004, compared with $1,187 million in the second quarter of 2003. In the June 2004 year-to-date period, net income was $3,691 million, compared with $2,408 million in the corresponding period of 2003. The improved results in both 2004 periods primarily were the result of improved U.S. refining margins and higher crude oil prices.

Income Statement Analysis

Sales and other operating revenues and purchase costs each increased 24 percent in the second quarter of 2004, and increased 17 and 18 percent, respectively, in the first six months. These increases mainly were due to:

- Higher petroleum product prices;
- Higher prices for crude oil;

- Increased volumes of natural gas bought and sold by our commercial organization in their role of optimizing the commodity flows of our E&P and R&M segments; and

- Higher excise, value added and other similar taxes.

Equity in earnings of affiliates increased 106 percent in the second quarter of 2004 and 188 percent in the six-month period. The increases in both periods reflect improved results from:

- Our heavy-oil joint ventures in Venezuela (Hamaca and Petrozuata), due to higher crude oil prices in both 2004 periods and higher production volumes in the 2004 six-month period;

- Our chemicals joint venture, Chevron Phillips Chemical Company LLC, due to higher volumes in both 2004 periods, higher aromatics margins in the 2004 second quarter, and higher ethylene margins in the 2004 six-month period;

- Our midstream joint venture, Duke Energy Field Services, LLC, reflecting higher natural gas liquids prices;

- Our joint-venture refinery in Melaka, Malaysia, due to improved refining margins in the Asia/Pacific region; and

- Our joint-venture delayed coker facilities at the Sweeny, Texas, refinery, Merey Sweeny LLP, due to higher light-heavy differentials.

Exploration expenses increased 15 percent in the second quarter of 2004 and 19 percent in the six-month period. The increases in both periods primarily were due to higher dry hole charges and leasehold impairments. Dry hole charges in the first six months of 2004 included exploratory activity in Alaska, the Gulf of Mexico, Venezuela, Canada and Vietnam. Significant leasehold impairments were recorded on leases in Brazil (BM-PAMA-3) and Nigeria (OPL 248).

Taxes other than income taxes increased 22 percent in the second quarter of 2004 and 21 percent in the first six months. Both increases mainly were the result of higher value-added taxes resulting from increased sales prices for European petroleum products and the impact of foreign currency translation.

Interest and debt expense declined 27 percent in the second quarter of 2004 and 33 percent in the six-month period. The decreases in both periods were primarily due to lower average debt levels during the 2004 periods and an increased amount of interest being capitalized.

Our effective tax rates for the second quarter and first six months of 2004 were 42 percent and 44 percent, respectively, compared with 38 percent and 46 percent for the corresponding periods in 2003. Tax law changes in certain international jurisdictions occurred during the second quarters of both 2003 and 2004. The benefit of the 2003 changes was greater than the 2004 changes, resulting in the lower effective tax rate in the second quarter of 2003, when compared with the corresponding period in 2004. The reduction in the effective tax rate for the first six months of 2004, versus the corresponding period in 2003, was mainly due to the impact of a higher proportion of income in lower tax rate jurisdictions, which more than offset the effect of international tax law changes.

We adopted Financial Accounting Standards Board Statement No. 143, “Accounting for Asset Retirement Obligations,” (SFAS No. 143) effective January 1, 2003. As a result, we recognized 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. We recognized a net $95 million charge in the six-month 2003 period for the cumulative effect of the two accounting changes.

Table of Contents

Restructuring Accruals

The information in Note 8-Restructuring, in the Notes to Consolidated Financial Statements, is incorporated herein by reference.

Segment Results

E&P

	Three Months Ended June 30		Six Months Ended June 30	
	2004	2003	**2004**	2003
	Millions of Dollars			
Net Income				
Alaska	**$ 397**	302	**800**	810
Lower 48	**274**	215	**506**	527
United States	**671**	517	**1,306**	1,337
International	**683**	560	**1,305**	1,007
	$ 1,354	1,077	**2,611**	2,344
	Dollars Per Unit			
Average Sales Prices				
Crude oil (per barrel)				
United States	**$ 36.22**	27.21	**34.45**	29.34
International	**34.58**	25.62	**33.02**	28.30
Total consolidated	**35.32**	26.33	**33.68**	28.76
Equity affiliates	**24.30**	16.85	**21.33**	18.02
Worldwide	**34.00**	25.19	**32.14**	27.82
Natural gas-lease (per thousand cubic feet)				
United States	**5.22**	4.58	**5.00**	4.96
International	**3.92**	3.47	**4.10**	3.70
Total consolidated	**4.44**	3.92	**4.46**	4.21
Equity affiliates	**.31**	4.89	**3.14**	4.85
Worldwide	**4.43**	3.93	**4.46**	4.21
	Millions of Dollars			
Worldwide Exploration Expenses				
General administrative; geological and geophysical; and lease rentals	**$ 58**	88	**114**	164
Leasehold impairment	**63**	24	**83**	44
Dry holes	**42**	30	**109**	50
	$ 163	142	**306**	258

Table of Contents

	Three Months Ended June 30		Six Months Ended June 30	
	2004	2003	**2004**	2003
	Thousands of Barrels Daily			
Operating Statistics				
Crude oil produced				
Alaska	**307**	331	**314**	334
Lower 48	**52**	57	**52**	58
United States	**359**	388	**366**	392
European North Sea	**276**	296	**279**	305
Asia Pacific	**88**	62	**86**	63
Canada	**25**	31	**26**	32
Other areas	**61**	73	**61**	73
Total consolidated	**809**	850	**818**	865
Equity affiliates	**104**	117	**109**	86
	913	967	**927**	951
Natural gas liquids produced				
Alaska	**23**	23	**25**	24
Lower 48	**26**	26	**25**	24
United States	**49**	49	**50**	48
European North Sea	**13**	9	**13**	10
Asia Pacific	**4**	1	**2**	1
Canada	**10**	11	**10**	11
Other areas	**3**	2	**3**	1
	79	72	**78**	71

	Millions of Cubic Feet Daily			
Natural gas produced*				
Alaska	**147**	162	**166**	175
Lower 48	**1,226**	1,311	**1,229**	1,324
United States	**1,373**	1,473	**1,395**	1,499
European North Sea	**1,124**	1,225	**1,162**	1,266
Asia Pacific	**284**	307	**295**	296
Canada	**437**	424	**432**	430
Other areas	**81**	56	**73**	54
Total consolidated	**3,299**	3,485	**3,357**	3,545
Equity affiliates	**4**	11	**6**	11
	3,303	3,496	**3,363**	3,556

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

	Thousands of Barrels Daily			
Mining operations				
Syncrude produced	**20**	19	**22**	18

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 June 30, 2004, our E&P operations were producing in the United States, Norway, the United Kingdom, Canada, Nigeria, Venezuela, offshore Timor Leste in the Timor Sea, Australia, China, Indonesia, the United Arab Emirates, Vietnam, and Russia.

Net income from the E&P segment increased 26 percent in the second quarter of 2004, and 11 percent in the six-month period. In both periods, the increases were primarily due to higher crude oil prices and, to a lesser extent, higher natural gas and natural gas liquids prices, partially offset by lower crude oil and natural gas production. In addition, certain tax benefits recognized in the second quarter of 2003 were in excess of those recognized in the second quarter of 2004. The 2003 six-month period included a net benefit of $142 million for the cumulative effect of accounting changes (SFAS No. 143 and FIN 46).

U.S. E&P

Net income from our U.S. E&P operations increased 30 percent in the second quarter of 2004, and declined 2 percent in the six-month period. The quarterly increase was mainly the result of higher crude oil prices and, to a lesser extent, higher natural gas and natural gas liquids prices, partially offset by lower production volumes. Results declined in the six-month period of 2004 because increased crude oil and natural gas prices were more than offset by lower production volumes and a net benefit of $142 million in the 2003 six-month period for the cumulative effect of accounting changes (SFAS No. 143 and FIN 46).

U.S. E&P production on a barrel-of-oil-equivalent (BOE) basis averaged 637,000 barrels per day in the second quarter of 2004, down 7 percent from 683,000 BOE per day in the second quarter of 2003. The decreased production primarily was the result of asset dispositions and field production declines.

International E&P

Net income from our international E&P operations increased 22 percent in the second quarter of 2004, and 30 percent in the six-month period. The increases in both periods primarily were due to higher crude oil prices and, to a lesser extent, higher natural gas and natural gas liquids prices. Higher prices were partially offset in the second quarter by lower crude oil and natural gas production. In addition, certain tax and other benefits recognized in the second quarter of 2003 were in excess of those recognized in the second quarter of 2004. In the second quarter of 2004, we recorded leasehold impairments in Brazil (BM-PAMA-3) and Nigeria (OPL 248) totaling $9 million after-tax after unsuccessful exploratory efforts. International E&P's net income in the second quarter of 2003 was favorably impacted by the Norway Removal Grant Act (1986) repeal and the realignment of ownership interests in the Bayu-Undan project in the Timor Sea, along with the ratification of the Australia/Timor-Leste treaty. Together, these items contributed $138 million to second quarter 2003 net income. Net income in the second quarter of 2004 was favorably impacted $31 million primarily by tax rate changes in Canada.

International E&P production on a barrel-of-oil-equivalent (BOE) basis averaged 906,000 barrels per day in the second quarter of 2004, down 4 percent from 939,000 BOE per day in the second quarter of 2003. Production was favorably impacted in 2004 by the startup of production from the Su Tu Den field in Vietnam in late 2003 and the ramp up of the Bayu-Undan field in the Timor Sea. These items were more than offset by asset dispositions and field production declines.

Table of Contents

Midstream

	Three Months Ended June 30		Six Months Ended June 30	
	2004	2003	**2004**	2003
	Millions of Dollars			
Net income*	**$ 42**	25	**97**	56
**Includes DEFS-related net income:*	***$ 33***	*23*	***66***	*36*

	Dollars Per Barrel			
Average Sales Prices				
U.S. natural gas liquids*				
Consolidated	**$26.42**	20.99	**26.05**	23.29
Equity	**25.61**	20.53	**25.21**	22.53

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

	Thousands of Barrels Daily			
Operating Statistics				
Natural gas liquids extracted*	**178**	209	**200**	216
Natural gas liquids fractionated**	**187**	207	**204**	217

* *Includes our share of equity affiliates.*
** *Excludes DEFS.*

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. The Midstream segment consists of our 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 68 percent in the second quarter of 2004, and 73 percent in the six-month period. The improvements were primarily attributable to improved results from DEFS, which had:

- Higher gross margins, primarily reflecting higher natural gas liquids prices;
- Lower operating and maintenance expenses, along with lower net interest expense; and
- In the six-month period results, a $23 million (gross) charge in the first six months of 2003 for the cumulative effect of accounting changes, mainly related to the adoption of SFAS No. 143.

Our Midstream operations outside of DEFS also benefited from improved natural gas liquids prices, as well as gains from asset dispositions of $12 million, after-tax, in the second quarter of 2004. Included in the dispositions was the sale to DEFS of certain assets located in New Mexico. These items were partially offset by property impairments of $16 million before-tax, $10 million after-tax, related to planned dispositions. For the six-month period of 2004, property impairments related to planned dispositions totaled $36 million before-tax, $22 million after-tax.

Included in the Midstream segment's net income was a benefit of $9 million in the second quarter of 2004, the same as the second quarter of 2003, 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. The corresponding amount in both six-month periods was $18 million.

Table of Contents

R&M

	Three Months Ended June 30		Six Months Ended June 30	
	2004	2003	**2004**	2003
	Millions of Dollars			
Net Income				
United States	$ **734**	248	**1,137**	398
International	**84**	73	**145**	187
	$ **818**	321	**1,282**	585
	Dollars Per Gallon			
U.S. Average Sales Prices*				
Automotive gasoline				
Wholesale	$ **1.40**	1.01	**1.28**	1.06
Retail	**1.61**	1.34	**1.47**	1.36
Distillates-wholesale	**1.17**	.85	**1.09**	.95

**Excludes excise taxes.*

	Three Months Ended June 30		Six Months Ended June 30	
	2004	2003	**2004**	2003
	Thousands of Barrels Daily			
Operating Statistics				
Refining operations*				
United States				
Rated crude oil capacity	**2,168**	2,168	**2,168**	2,168
Crude oil runs	**2,119**	2,128	**2,112**	2,068
Capacity utilization (percent)	**98%**	98	**97**	95
Refinery production	**2,300**	2,357	**2,273**	2,305
International				
Rated crude oil capacity	**447**	442	**447**	442
Crude oil runs	**276**	376	**325**	386
Capacity utilization (percent)	**62%**	85	**73**	87
Refinery production	**318**	407	**364**	421
Worldwide				
Rated crude oil capacity	**2,615**	2,610	**2,615**	2,610
Crude oil runs	**2,395**	2,504	**2,437**	2,454
Capacity utilization (percent)	**92%**	96	**93**	94
Refinery production	**2,618**	2,764	**2,637**	2,726

**Includes ConocoPhillips' share of equity affiliates.*

Petroleum products outside sales				
United States				
Automotive gasoline	**1,328**	1,381	**1,321**	1,356
Distillates	**538**	590	**554**	595
Aviation fuels	**191**	164	**185**	164
Other products	**573**	493	**545**	501
	2,630	2,628	**2,605**	2,616
International	**440**	448	**472**	438
	3,070	3,076	**3,077**	3,054

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 petroleum products, and transporting, distributing and marketing petroleum products. R&M has operations in the United States, Europe and Asia Pacific.

Net income from the R&M segment increased 155 percent in the second quarter of 2004, and 119 percent in the first six months. The increase in both periods of 2004 primarily was due to higher refining margins, partially offset by lower wholesale and retail marketing margins. In the six-month period comparison, the 2003 period included a $125 million net charge for the cumulative effect of accounting changes (FIN 46).

During the second quarter of 2004, we performed a review of the crude oil refining capacities for our worldwide refining operations. We utilize a “barrels-per-calendar-day” methodology, which includes allowances for maintenance turnarounds, regulatory constraints, crude oil quality and reliability. As a result of this review, effective July 1, 2004, our total U.S. rated crude oil capacity was revised downward slightly, from 2,168 thousand barrels per day to 2,160 thousand barrels per day, while our international refining capacity decreased from 447 thousand barrels per day to 428 thousand barrels per day.

U.S. R&M

Net income from our U.S. R&M operations increased 196 percent in the second quarter of 2004, and 186 percent in the first six months. The increase in the second quarter and six-month period of 2004 primarily was due to higher refining margins, partially offset by lower wholesale and retail marketing margins. In the six-month period comparison, the 2003 period included a $125 million net charge for the cumulative effect of accounting change (FIN 46).

Our U.S. crude oil refining capacity utilization rate was 98 percent in the second quarter of 2004, the same as the second quarter of 2003. However, realized refining margins were negatively impacted in the quarter due to lower clean product yield as a result of unplanned cracking unit downtime at the Trainer, Pennsylvania, refinery and an extended cracking unit turnaround at the Alliance, Louisiana, refinery. This unplanned downtime also resulted in higher maintenance costs in the quarter.

International R&M

Net income from our international R&M operations increased 15 percent in the second quarter of 2004, and decreased 22 percent in the first six months. The increase in the second quarter of 2004 primarily was due to higher refining margins, partially offset by higher maintenance expenses and lower refining production volumes due to turnaround activity, and lower retail marketing margins. In the six-month period, higher refining margins were more than offset by lower retail marketing margins, lower refining production volumes and higher maintenance expenses due to turnaround activity, and the effect of foreign currency transaction gains and losses.

Our international crude oil refining capacity utilization rate was 62 percent in the second quarter of 2004, compared with 85 percent in the second quarter of 2003. The lower rate in the second quarter of 2004 primarily was due to maintenance turnarounds at most of our international refineries, including a 43-day turnaround at the Humber refinery in the United Kingdom.

Chemicals

	Millions of Dollars			
	Three Months Ended June 30		Six Months Ended June 30	
	2004	2003	**2004**	2003
Net income (loss)	**$ 46**	12	**85**	(11)

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.

Net income from the Chemicals segment increased $34 million in the second quarter of 2004, compared with the second quarter of 2003. In the six-month period, the Chemicals segment had net income of $85 million in 2004, compared with a net loss of $11 million in 2003. The improvement in both periods reflects that CPChem had improved equity earnings from Qatar Chemical Company Ltd. (an olefins and polyolefins complex in Qatar) and Saudi Chevron Phillips Company (an aromatics complex in Saudi Arabia). In addition, both 2004 periods included favorable adjustments recorded by ConocoPhillips for the finalization of property damage third-party insurance claims. The improvement in the six-month period of 2004 also reflects higher ethylene margins.

Emerging Businesses

	Millions of Dollars			
	Three Months Ended June 30		Six Months Ended June 30	
	2004	2003	**2004**	2003
Net Loss				
Technology solutions	**$ (4)**	(6)	**(8)**	(11)
Gas-to-liquids	**(7)**	(13)	**(16)**	(33)
Power	**(16)**	(1)	**(20)**	—
Other	**(2)**	(3)	**(7)**	(13)
	$ (29)	(23)	**(51)**	(57)

The Emerging Businesses segment includes the development of new businesses outside our traditional operations. Emerging Businesses incurred a net loss of $29 million in the second quarter of 2004, compared with a net loss of $23 million in the second quarter of 2003. In the six-month period, Emerging Businesses incurred a net loss of $51 million in 2004, compared with a net loss of $57 million in 2003. Both 2004 periods reflect increased costs associated with our Immingham power plant project in the United Kingdom, which is now in the initial commissioning phase of the project. Prior to the initial commissioning phase, most costs associated with this project were capitalized as construction costs. Partially offsetting the higher Immingham costs in the second quarter of 2004, and more than offsetting them in the six-month period, were:

- Lower research and development costs, compared with the 2003 periods, which included the costs of a demonstration gas-to-liquids plant then under construction. Construction was substantially completed during the second quarter of 2003; and

- Elimination of costs associated with a carbon fibers project that was terminated during 2003.

Corporate and Other

	Millions of Dollars			
	Three Months Ended June 30		Six Months Ended June 30	
	2004	2003	**2004**	2003
Net Income (Loss)				
Net interest	$ **(119)**	(145)	**(223)**	(335)
Corporate general and administrative expenses	**(54)**	(43)	**(109)**	(73)
Discontinued operations	**62**	91	**75**	144
Merger-related costs	**—**	(115)	**(14)**	(142)
Cumulative effect of accounting changes	**—**	—	**—**	(112)
Other	**(45)**	(13)	**(62)**	9
	$ **(156)**	(225)	**(333)**	(509)

After-tax net interest consists of interest and financing expense, net of interest income and capitalized interest, as well as premiums incurred on the early retirement of debt. Net interest decreased 18 percent in the second quarter of 2004, and 33 percent in the six-month period. The decreases in both periods primarily were due to lower average debt levels, an increased amount of interest being capitalized in the 2004 periods, and lower charges for premiums paid on the early retirement of debt.

After-tax corporate general and administrative expenses increased 26 percent in the second quarter of 2004, and 49 percent in the first six months. The increases in both periods primarily were due to increased compensation costs, as well as increases in various other staff costs. The increases in compensation costs included higher stock-based compensation, which reflected both an increase in the number of units issued and our higher stock prices in the 2004 periods.

Income from discontinued operations decreased 32 percent in the second quarter of 2004, and 48 percent in the six-month period. The decreases reflect asset dispositions completed during 2003 and 2004, partially offset by gains on asset dispositions in the second quarter of 2004.

Beginning with the second quarter of 2004, we no longer separately identify merger-related costs because these activities have been substantially completed.

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 lower in both 2004 periods, primarily due to the unfavorable impact of foreign currency transactions and the inclusion in the 2003 periods of gains related to insurance demutualization benefits.

Table of Contents

CAPITAL RESOURCES AND LIQUIDITY

Financial Indicators

	Millions of Dollars	
	At June 30 2004	At December 31 2003
Current ratio	**.9**	.8
Total debt repayment obligations due within one year	**$ 1,241**	1,440
Total debt	**$ 15,619**	17,780
Minority interests	**$ 1,048**	842
Common stockholders' equity	**$ 37,826**	34,366
Percent of total debt to capital*	**29%**	34
Percent of floating-rate debt to total debt	**14%**	17

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

To meet our short- and long-term liquidity requirements, including funding our capital program, paying dividends and repaying debt, we look to a variety of funding sources, primarily cash from operating activities. In addition, during the first half of 2004, we raised approximately $1.4 billion in funds from the sale of assets. During the first six months of 2004, available cash was used to support our ongoing capital expenditure program, reduce debt and pay dividends. Total dividends paid on common stock during the first half of 2004 were $590 million. During the first six months of 2004, cash and cash equivalents increased $314 million to $804 million.

Our cash flows from operating activities for both the short- and long-term are highly dependent upon prices for crude oil, natural gas and natural gas liquids, as well as refining and marketing margins. During 2003 and the first six months of 2004, we benefited from high crude oil and natural gas prices, as well as improved refining margins. The sustainability of these prices and margins are driven by market conditions over which we have no control. In addition, the level of our production volumes of crude oil, natural gas and natural gas liquids also impacts our cash flows. These production levels are impacted by such factors as acquisitions and dispositions of fields, field production decline rates, new technologies, operating efficiency, the addition of proved reserves through exploratory success, and the timely and cost-effective development of those proved reserves. We will need to continue to add to our proved reserve base through exploration and development of new fields, or by acquisition, and to apply new technologies and processes to boost recovery from existing fields in order to maintain or increase production and proved reserves. We have been successful in the past in maintaining or adding to our production and proved reserve base and anticipate being able to do so in the future. Our barrel-of-oil-equivalent (BOE) production has increased in each of the past three years. Our 2003 production of 1.59 million BOE per day included approximately 60,000 BOE per day from assets that were sold during 2003 or early 2004. After adjusting 2003 production volumes for the impact of these asset dispositions, we expect our 2004 production level to be similar to the adjusted 2003 level of 1.53 million BOE per day. In 2005 and 2006, we expect our annual average BOE production level to increase approximately 5 percent in each year as a result of projects currently scheduled to begin production in those years. We have replaced more than 100 percent of our BOE production in each of the past three years and we expect our average reserve replacement to exceed 100 percent of our production over the next three years. However, these anticipated results are subject to risks including reservoir performance; operational downtime; finding and development execution; obtaining management, Board of Director and third-party approval of development projects in a timely manner; regulatory changes; geographical location; market prices; and environmental issues; and therefore, cannot be assured.

In addition to cash flows from operating activities and proceeds from asset sales, we also rely on our commercial paper and credit facility programs, as well as our $5 billion universal shelf registration statement, to support our short- and long-term liquidity requirements. We anticipate that these sources of liquidity will be adequate to meet our funding requirements in 2004 through 2006, including our capital spending program and required debt payments.

Our cash flows from operating activities increased in each of the annual periods from 2001 through 2003. In addition to favorable market conditions, major acquisitions and mergers played a significant role in the upward trend of our cash flows from operating activities. The most significant event during this period was the merger of Conoco and Phillips on August 30, 2002. Phillips was designated as the acquirer for accounting purposes, so 2002 operating cash flows included eight months (January through August) of Phillips' activity only and four months of ConocoPhillips' activity (September through December), while 2003 includes the first full year of ConocoPhillips' activity. Absent any other significant acquisitions or mergers during 2004, we expect that market conditions, as discussed in our 2003 Form 10-K in the Results of Operations section of Management's Discussion and Analysis beginning on page 39, will be the most important factor affecting our 2004 cash flows, when compared with 2003.

Significant Sources of Capital

Operating Activities
During the first six months of 2004, cash of $4,349 million was provided by operating activities, a decrease of $917 million, compared with the same period in 2003. This decrease in cash provided by operating activities was primarily due to an increase in working capital, partially offset by an increase in income from continuing operations. The working capital increase primarily was driven by a higher retained interest in receivables sold to a Qualifying Special Purpose Entity (QSPE), timing of excise tax payments and a temporary increase in inventories. For additional information on income from continuing operations, see the discussion of the Results of Operations included in Management's Discussion and Analysis of Financial Condition and Results of Operations beginning on page 32. For additional information on receivables sold to a QSPE, see Receivables Monetization in the Off-Balance Sheet Arrangements discussion included in Management's Discussion and Analysis of Financial Condition and Results of Operations on page 46.

Asset Sales
Following the merger of Conoco and Phillips in August of 2002, we initiated an asset disposition program. At the end of 2003 our initial target, to sell approximately $3 billion to $4 billion of assets by the end of 2004, was raised to approximately $4.5 billion by the end of 2004. During the first six months of 2004, proceeds from asset sales were $1.4 billion, bringing total proceeds to approximately $4.7 billion since the program began. While we will continue to have modest asset disposition activity, this essentially completes this asset disposition program.

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 downstream margins, as well as periodic cash needs to make tax payments and purchase crude oil, natural gas and petroleum products. 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 kept within 90 days. At June 30, 2004, we had $4 billion available under the commercial paper program as there was no commercial paper outstanding, compared with $709 million of commercial paper outstanding at December 31, 2003.

At June 30, 2004, we had a $1.5 billion, 364-day revolving credit facility expiring on October 13, 2004; two revolving credit facilities totaling $2 billion expiring in October 2006; and a $500 million facility expiring in October 2008 that supported our $4 billion commercial paper program. There were no outstanding borrowings under any of these facilities at June 30, 2004. One of our Norwegian subsidiaries had two $300 million revolving credit facilities that expired in June 2004, which were not renewed.

Minority Interests
At June 30, 2004, we had outstanding $1,048 million of equity that was held by minority interest owners, including a net minority interest of $503 million in Ashford Energy Capital S.A. Also included in the June 30 balance, was a $141 million net minority interest in Conoco Corporate Holdings L.P., which we retired on July 8, 2004. The remaining minority interest amounts relate to controlled operating joint ventures with minority interest owners. The largest of these, $391 million, related to the Bayu-Undan liquefied natural gas project in the Timor Sea.

Receivables Factoring
At December 31, 2003, we had sold $226 million of receivables under a factoring arrangement. We retained servicing responsibility for these sold receivables, which gave us certain benefits, the fair value of which approximated the fair value of the liability incurred for continuing to service the receivables. At June 30, 2004, we had no receivables outstanding under similar arrangements.

Off-Balance Sheet Arrangements

Receivables Monetization
At June 30, 2004, certain credit card and trade receivables had been sold to a Qualifying Special Purpose Entity (QSPE) in a revolving-period securitization arrangement. This arrangement provides for us to sell, and the QSPE to purchase, certain receivables, and for the QSPE to then issue beneficial interests of up to $1.2 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 QSPE because it meets 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.

At June 30, 2004, and December 31, 2003, the QSPE had issued beneficial interests to the bank-sponsored entities of $525 million and $1.2 billion, respectively. The receivables transferred to the QSPE met the isolation and other requirements of SFAS No. 140 to be accounted for as sales and were accounted for accordingly.

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 $2.9 billion at June 30, 2004, and $1.3 billion at December 31, 2003. We also retain servicing responsibility related to the sold receivables, which gives us certain rights and abilities, the fair value of which approximates the fair value of the liability incurred for continuing to service the receivables. The carrying value of our subordinated beneficial interests in the QSPE approximates fair market value due to the very short term of the underlying assets. See Note 14-Sales of Receivables, in the Notes to Consolidated Financial Statements, for additional information.

Table of Contents

Capital Requirements

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

Our balance sheet debt at June 30, 2004, was $15.6 billion. This reflects debt reductions of approximately $2.2 billion during the first six months of the year. The reduction primarily resulted from repayment of the $1,350 million aggregate principal amount of our 5.90% Notes due 2004 at maturity in April and a reduction in commercial paper. In addition, we have given notice to redeem the $1,150 million aggregate principal amount of our 8.5% Notes due 2005 in August of 2004.

As of June 30, 2004, our aggregate contractual fixed and variable obligations had not changed significantly from those reported on December 31, 2003.

Capital Spending

Capital Expenditures and Investments

	Millions of Dollars	
	Six Months Ended June 30	
	2004	2003
E&P		
United States-Alaska	$ **324**	289
United States-Lower 48	**290**	418
International	**1,835**	1,472
	2,449	2,179
Midstream	**5**	4
R&M		
United States	**365**	324
International	**128**	124
	493	448
Chemicals	**—**	—
Emerging Businesses	**55**	164
Corporate and Other*	**63**	70
	$ **3,065**	2,865
United States	$ **1,047**	1,120
International	**2,018**	1,745
	$ **3,065**	2,865
Discontinued operations	$ **1**	56

**Excludes discontinued operations.*

E&P

In Alaska, we continued development drilling in the Greater Kuparuk Area, the Greater Prudhoe Area, the Alpine field and the development of West Sak's heavy-oil accumulations. In addition, we are on track to increase oil production capacity at the Alpine field with Alpine Capacity Expansion (ACX)-Phase 1 and Phase 2 expected to start up in the second half of 2004 and to complete the final component of Phase 2 in mid-2005. The capacity expansion projects are expected to increase water, oil and gas handling capacities, all of which are important for oil production and maintaining reservoir pressure.

During the 2004 winter drilling season, we drilled five North Slope exploration wells, which resulted in two successful appraisal wells in the National Petroleum Reserve-Alaska (NPR-A) and three wells that were expensed as dry holes. One of the two successful appraisal wells tested and flowed at an unstimulated rate of 24 million cubic feet of natural gas per day and 1,250 barrels of condensate per day. We were also the successful bidder on 71 tracts covering over 808 thousand gross acres, approximately 514 thousand net acres, at the June Bureau of Land Management oil and gas lease sale for the Northwest Planning Area of the NPR-A. As a result of this additional acreage, we now have under lease approximately 1.3 million net exploration acres in the NPR-A.

The owners of the Trans-Alaska Pipeline System (TAPS) have approved plans to invest over $250 million in a project to upgrade the pipeline’s pump stations. Our share in this project is approximately $70 million. The project is expected to be substantially complete by the end of 2005 and should reduce operating costs and extend the economic life of the pipeline through increased efficiencies, while maintaining high safety and environmental performance standards.

We continued with the construction of our double-hulled Endeavour Class tankers, which are used in transporting Alaskan crude oil to the U.S. West Coast. We expect to add a new Endeavour Class tanker to our fleet in both 2004 and 2005.

In the Lower 48, we continued with the development of the deepwater Magnolia field, where production is anticipated to start up in late 2004. We are the operator of the Magnolia project with a 75 percent interest. In the first quarter, on behalf of the Garden Banks 783/784 unit, we filed an application for royalty relief with the Minerals Management Service (MMS). Royalty relief may be granted if the value of the project using the MMS economic model and criteria is insufficient to recover the project investment without the relief. There is no assurance that such relief will be granted. Company sanction of the K2 offshore development project in the Gulf of Mexico occurred in the first quarter of 2004. The K2 project involves tieback of subsea wells to an existing platform in a nearby block, with startup targeted for late 2005.

We continued development of the Syncrude Stage III expansion-mining project in the Canadian province of Alberta, where an upgrader expansion project is expected to start up by mid-2006.

Also in Canada, development expenditures have started for the Surmont heavy-oil project. In 2003, we booked 223 million barrels of proved crude oil reserves from our Canadian operations, the majority of which related to the Surmont heavy-oil project. The Surmont project, which we operate, uses an enhanced thermal oil recovery method called steam assisted gravity drainage. This process involves heating the oil by the injection of steam deep into the oil sands through a horizontal well bore, effectively lowering the viscosity and enhancing the flow of the oil, which is then recovered via gravity drainage into a lower horizontal well bore and pumped to the surface. As a result of using this oil recovery method, production costs for the project are expected to be higher than our average production costs, but we anticipate that the average production costs per barrel over the life of the project will not be significantly higher than that of our conventional projects in western Canada, as disclosed in our supplemental oil and gas disclosures in our 2003 Form 10-K. Over the life of this 30+ year project, we anticipate that 498 production and steam-injection well pairs will be drilled, with our share of the project costs estimated at $1 billion. During the first six months of 2004, our capital expenditures associated with Surmont were approximately $10 million, and commercial production is expected to begin in 2006. We anticipate peak production to occur in 2012, at an estimated net rate of 47,000 barrels per day. Surmont is an integrated project for us as we anticipate using our share of the heavy oil produced as a feedstock in our U.S. refineries.

At our Hamaca project in Venezuela, we continued activities required to produce, transport and upgrade 8.6-degree API extra-heavy crude into medium-grade crude oil. We anticipate completing the construction of the upgrader in the fourth quarter of 2004, at which time our net production from the Hamaca field is expected to increase from the average rate of 32,000 barrels per day in the second quarter of 2004 to approximately 71,000 barrels per day.

In Brazil, after further evaluation, we wrote-off our remaining leasehold investment in Block BM-PAMA-3 in April 2004. Once approval is received from the Brazilian government, we plan to cease all operations there and exit the country. We expect to receive governmental approval in the third quarter of 2004.

In the U.K. and Norwegian sectors of the North Sea, we continued with several exploration and development projects, including the Ekofisk Area growth project, which consists of construction and installation of a new steel wellhead and processing platform and an increase in capacity from existing facilities; development of the U.K. Clair field, where production is expected in late 2004; and development of Britannia satellite fields, Callanish and Brodgar, where production is expected in 2007.

In the North Caspian region, detailed design, procurement and construction activities continued on the Kashagan oil field development following approval by the Republic of Kazakhstan for the development plan and budget in February 2004. During 2003, we exercised our pre-emptive rights related to BG International’s (BG) sale of their share in the North Caspian License that includes the Kashagan field. If we obtain approval from the Republic of Kazakhstan, our ownership interest would increase from 8.33 percent to 10.19 percent. In the South Caspian, operations continued on the Zafar-Mashal #1 exploration well in Azerbaijan waters. Drilling is expected to be completed in the third quarter of 2004.

In China’s Bohai Bay, we continued to evaluate development plans for Phase II of the Peng Lai 19-3 oil field. Phase II is expected to include multiple wellhead platforms, central processing facilities and a floating production, storage and offloading facility (FPSO). In conjunction with Phase II, we plan to develop the Peng Lai 25-6 oil field, located three miles east of Peng Lai 19-3. The Peng Lai 19-9 oil field, located two miles east of the Peng Lai 19-3, is also expected to be a part of the Phase II development.

In the Timor Sea, commissioning of the Bayu-Undan gas recycle project is under way. First liquids production began in February 2004. Peak capacity, 62,000 net barrels per day of condensate and 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.

Also during the first six months of 2004, we continued with the gas development project for Bayu-Undan, which includes a liquefied natural gas (LNG) plant near Darwin, Australia, as well as a gas pipeline from Bayu-Undan to the LNG facility. At the end of June, the LNG project was nearly 50 percent complete and mobilization of the barge to lay the gas pipeline was in progress. The first LNG cargo from the 3.52 million-ton-per-year facility is scheduled for delivery in early 2006. We own a 56.72 percent interest in the integrated gas development project.

In Indonesia, we completed the construction of the South Jambi gas project in the South Jambi B Block in South Sumatra with first production occurring in June 2004. We continued the construction of the Belanak FPSO and the development of the Belanak field in the South Natuna Sea Block B. All of the topside modules have been loaded onto the Belanak FPSO vessel, and commissioning of the topsides is currently under way. Commercial production from Belanak is targeted to commence in 2005. Also, in Block B we began development of the Kerisi and Hiu fields.

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. During these years, we converted on average approximately 15 percent per year of our proved undeveloped reserves to proved developed reserves. As of December 31, 2003, estimated future development costs relating to the development of proved undeveloped reserves for the years 2004 through 2006 were projected to be $1,767 million, $1,111 million, and $659 million, respectively. Of our 2,572 million barrel-of-oil-equivalent proved undeveloped reserves at year-end 2003, approximately 85 percent were associated with 12 major developments. Of these 12, five are expected to have significant conversions of proved undeveloped reserves to proved developed reserves during 2004, 2005 and 2006 (with expected year of conversion noted parenthetically):

- Bayu-Undan field in the Timor Sea (2004 for condensate and natural gas liquids and 2006 for natural gas);
- Surmont heavy-oil project in Canada (2006);
- Nigeria natural gas reserves (2005);
- Belanak field, offshore Indonesia (2005); and
- Magnolia field in the Gulf of Mexico (2004).

The remaining seven developments are currently producing and are expected to have additional proved reserves convert from undeveloped to developed over time as development activities continue and/or production facilities are expanded or upgraded:

- The Hamaca and Petrozuata heavy-oil projects in Venezuela;
- The Ekofisk, Eldfisk and Heidrun fields in the North Sea; and
- The Prudhoe Bay and Alpine fields on Alaska’s North Slope.

R&M

In the United States, we continued to expend funds related to clean fuels, safety and environmental projects. We also are investing in a new diesel hydrotreater at the Rodeo facility of our San Francisco-area refinery to produce reformulated California highway diesel an estimated one year ahead of the June 2006 deadline.

The integration of certain refining assets purchased adjacent to our Wood River refinery in Illinois was completed in the second quarter of 2004. Integration of the assets enables the refinery to process heavier, lower cost crude oil.

Internationally, we continued to invest in our ongoing refining and marketing operations, including the replacement of a catalytic reformer at our Humber refinery in the United Kingdom and a diesel clean fuels project at our refinery in Ireland.

Emerging Businesses

We continued to spend funds in the first half of 2004 to complete our Immingham combined heat and power cogeneration plant near our Humber refinery in the United Kingdom. We expect the plant to become operational in the third quarter of 2004.

Contingencies

Legal and Tax Matters

We accrue for contingencies when a loss is probable and 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 our financial statements.

Environmental

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

For example, the U.S. Environmental Protection Agency (EPA) 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. 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. The EPA responded by promulgating a revised implementation rule for its new 8-hour NAAQS on April 30, 2004. Several environmental groups have since filed challenges to this new rule. Depending upon the outcomes of the various challenges, area designations, and the resulting State Implementation Plans, 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.

From time to time, we 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, 2003, we reported we had been notified of potential liability under CERCLA and comparable state laws at 61 sites around the United States. At June 30, 2004, we had resolved four of these sites and had received five new notices of potential liability, leaving 62 unresolved sites where we have been notified of potential liability.

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

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 June 30, 2004.

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 June 30, 2004, our balance sheet included a total environmental accrual of $1,149 million, compared with $1,119 million at December 31, 2003. We expect to incur a substantial majority of these expenditures within the next 30 years.

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

NEW ACCOUNTING DEVELOPMENTS

In April 2004, the FASB issued FASB Staff Position Nos. FAS 141-1 and FAS 142-1, which amended SFAS Nos. 141, "Business Combinations," and 142, "Goodwill and Other Intangible Assets," to remove mineral rights as an example of an intangible asset. See Note 7-Properties, Plants and Equipment, in the Notes to Consolidated Financial Statements, for more information.

In January 2004 and May 2004, the FASB issued FASB Staff Position Nos.106-1 and 106-2, respectively, regarding accounting and disclosure requirements related to the Medicare Prescription Drug, Improvement and Modernization Act of 2003. See Note 15-Employee Benefit Plans, in the Notes to Consolidated Financial Statements, for additional information.

In March 2004, the EITF reached a consensuses on Issue 03-06, "Participating Securities and the Two-Class Method under FASB Statement No. 128, Earnings per Share". The EITF explains how to determine whether a security should be considered a "participating security" for purposes of computing earnings per share and how earnings should be allocated to a participating security when using the two-class method for computing basic earnings per share. The adoption of this standard in the second quarter of 2004 did not have a material effect on our earnings per share calculations for the periods presented.

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 in our 2003 Form 10-K and Note 2—Accounting Policies in the Notes to Consolidated Financial Statements in this quarterly report 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 Finance Committee on an annual basis. We believe the following discussions of critical accounting policies, along with the previous discussions of contingencies in our 2003 Form 10-K and this quarterly report and of deferred tax asset valuation allowances in our 2003 Form 10-K, address all important accounting areas where the nature of accounting estimates or assumptions is material due to the levels of subjectivity and judgment necessary to account for highly uncertain matters or the susceptibility of such matters to change.

Table of Contents

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 in our 2003 Form 10-K 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. At year-end 2003, the book value of the pools of property acquisition costs, that individually are relatively small and thus subject to the above-described periodic leasehold impairment calculation, was approximately $599 million and the accumulated impairment reserve was approximately $82 million. The weighted average judgmental percentage probability of ultimate failure was approximately 67 percent and the weighted average amortization period was approximately 3.7 years. If that judgmental percentage were to be raised by 5 percent across all calculations, the pre-tax leasehold impairment expense in 2004 would increase by $8 million. The remaining $3,663 million of capitalized unproved property costs at year-end 2003 consisted of individually significant leaseholds, mineral rights held into perpetuity by title ownership, exploratory wells currently drilling, and suspended exploratory wells, on which management periodically assesses for impairment based on exploration and drilling efforts to date on the individual prospects. Of this amount, approximately $2.5 billion is concentrated in 10 major projects, of which management expects approximately $1.1 billion to move to proved properties in 2004. See the following discussion of Exploratory Costs for more information on suspended exploratory wells.

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 of a sufficient quantity to justify completion of the find as a producing well. 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 infrastructure 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 drilling work in the area, remain capitalized on the balance sheet as long as additional exploratory drilling work is under way or firmly planned. In these situations, the well is considered to have found economic reserves if recoverable reserves have been found of a sufficient quantity to justify completion of the find as a producing well, assuming that the major infrastructure capital expenditure had already been made. Once all additional exploratory drilling work has been completed on projects requiring major infrastructure capital expenditures, the economic viability of the overall project is evaluated within one year of the last exploratory well completion. If considered to be economically viable, internal company approvals are then obtained to move the overall project toward a development stage project. If joint-venture partner and government approvals are required before development expenditures can begin, exploratory well costs remain capitalized as long as the company is actively pursuing such approvals and believes such approvals will be obtained. Once all required approvals have been obtained, such projects are moved into development stage status, which corresponds with the time period of reporting proved oil and gas reserves for the find. 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 drilling 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 in our 2003 Form 10-K 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. At the end of 2003, 2002 and 2001, the book values of suspended exploratory well costs were approximately $403 million, $221 million and $189 million, respectively. Dry hole expense in 2003, 2002 and 2001 included $29 million, $34 million and $7 million, respectively, of write-offs of exploratory well investments that had been incurred and suspended in a prior year.

Proved Oil and Gas Reserves and Canadian Syncrude Reserves
Engineering estimates of the quantities of recoverable oil and gas reserves in oil and gas fields and in-place crude bitumen volumes in oil sand mining operations are inherently imprecise and represent only approximate amounts because of the subjective judgments involved in developing such information. Reserve estimates are based on subjective judgments involving geological and engineering assessments of in-place hydrocarbon volumes, the production or mining plan, historical extraction recovery and processing yield factors, installed plant operating capacity and operating approval limits. The reliability of these estimates at any point in time depends on both the quality and quantity of the technical and economic data and the efficiency of extracting and processing the hydrocarbons. Despite the inherent imprecision in these engineering estimates, accounting rules require disclosure of “proved” reserve estimates due to the importance of these estimates to better understand the perceived value and future cash flows of a company’s E&P operations. There are several authoritative guidelines regarding the engineering criteria that have to be met before estimated 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 or oil sand mining operation. Also, as required by authoritative guidelines, the estimated future date when a field or oil sand mining operation will be permanently shutdown for economic reasons is based on an extrapolation of sales prices and operating costs prevalent at the balance sheet date. This estimated date when production will end affects the amount of estimated recoverable reserves. Therefore, as prices and cost levels change from year to year, the estimate of proved reserves also changes.

The judgmental estimation of proved reserves also is important to the income statement because the proved oil and gas reserve estimate for a field or the estimated in-place crude bitumen volume for an oil sand mining operation serves as the denominator in the unit-of-production calculation of depreciation, depletion and amortization of the capitalized costs for that asset. At year-end 2003, the net book value of productive E&P property, plant and equipment subject to a unit-of-production calculation, including our Canadian Syncrude bitumen oil sand assets, was approximately $20.3 billion and the depreciation, depletion and amortization recorded on these assets in 2003 was approximately $2.4 billion. The estimated proved developed oil and gas reserves on these fields were 5.1 billion barrels-of-oil-equivalent at the beginning of 2003 and were 4.7 billion barrels-of-oil-equivalent at the end of 2003. The estimated proved reserves on these Canadian Syncrude assets were 272 million barrels at the beginning of 2003 and were 265 million barrels at the end of 2003. If the judgmental estimates of proved reserves used in the unit-of-production calculations had been lower by 5 percent across all calculations, pre-tax depreciation, depletion and amortization in 2003 would have been increased by an estimated $92 million. Impairments of producing oil and gas properties in 2003, 2002 and 2001 totaled $225 million, $49 million and $23 million, respectively. Of these writedowns, only $19 million in 2003 and $23 million in 2002 were due to downward revisions of proved reserves. The remainder of the impairments resulted either from properties being designated as held for sale or from the repeal of the Norway Removal Grant Act (1986) that increased asset removal obligations.

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 and Note 7—Properties, Plants and Equipment, in the Notes to Consolidated Financial Statements in our 2003 Form 10-K and 2004 second-quarter Form 10-Q, respectively, 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 in our 2003 Form 10-K, 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 of Conoco and Phillips 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 in our 2003 Form 10-K and Note 7—Properties, Plants and Equipment, in the Notes to Consolidated Financial Statements in this report, for additional information.

Also in connection with the acquisition of Tosco and the merger of Conoco and Phillips, 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 of Conoco and Phillips 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

In E&P, we expect our worldwide production for the third quarter of 2004 to be below our second quarter level, primarily because of scheduled maintenance, normal seasonal declines and normal field declines. These declines are expected to be partly offset by the continued ramp up of liquids production at Bayu-Undan.

In R&M, we expect our average refinery crude oil utilization rate for the third quarter of 2004 to be in the mid-90 percent range.

In Venezuela, the date for the Presidential Recall Referendum has been announced for August 15, 2004. Potential political violence in connection with the Referendum could significantly impact our operations in the country.

In the second quarter, Norwegian authorities ordered us to upgrade our facilities at two Ekofisk Area installations — Ekofisk and Eldfisk — and have given us until October 1, 2004, to submit a plan for implementing measures to ensure workers are not disturbed by noises while they are resting. Norwegian authorities contend we are not in compliance with regulatory requirements for rest and restitution on the installations where there are shared sleeping quarters. While we believe we are fulfilling the requirements, we initially estimate it could require us to invest an estimated $114 million to comply with their order for temporary and permanent measures at Eldfisk and temporary measures at Ekofisk. We are appealing this order.

In early July 2004, we announced the finalization of our transaction with Freeport LNG Development, L.P. (L.P.) to participate in a proposed liquefied natural gas (LNG) receiving terminal in Quintana, Texas. Approval from the Federal Energy Regulatory Commission (FERC) was received in June 2004. Receipt of all other necessary federal, state and local approvals is expected in the third or fourth quarter of this year. Construction is scheduled to begin in the fourth quarter of 2004, with commercial startup planned for the second half of 2007. We will not have an ownership interest in the facility, but we will have a 50 percent interest in the general partnership managing the venture. We have entered into a credit agreement with the L.P., whereby we will provide financing support of up to $550 million for the construction of the facility.

Also in July 2004, we announced that we had signed a non-binding Memorandum of Understanding with Sound Energy Solutions (SES), a wholly owned subsidiary of Mitsubishi Corporation, to work jointly on the continuing development of the proposed SES LNG import terminal to be located in the Port of Long Beach, California. The terminal is expected to have a send-out capacity of 700 million cubic feet per day with a peak capacity of 1 billion cubic feet per day. The facility could become operational in 2008 upon receiving permit approval from the FERC and California state agencies.

Compared with the more global nature of crude oil commodity pricing, natural gas prices have historically varied more in different regions of the world. We produce natural gas from regions around the world that have significantly different supply, demand and regulatory circumstances, typically resulting in significantly lower average sales prices than in the Lower 48 region of the United States. Moreover, excess supply conditions that exist in certain parts of the world cannot easily serve to mitigate the relatively high-price conditions in the U.S. Lower 48 states and other markets because of a lack of infrastructure and because of the difficulties in transporting the natural gas. We, along with other companies in the oil and gas industry, are planning long-term projects in regions of excess supply to install the infrastructure required to produce and liquefy natural gas for transportation by tanker and subsequent regasification in regions where market demand is strong, such as to the U.S. Lower 48 states or certain parts of Asia, but where supplies are not as plentiful. Since natural gas prices in regions of excess supply are expected to remain well below the sales prices for natural gas that is produced closer to areas of high demand, it is economically more attractive to invest in long-term LNG projects than to sell into the local markets at much lower prices.

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

This report includes forward-looking statements within the meaning of Section 27A of the Securities Act of 1933 and Section 21E of the Securities Exchange Act of 1934. You can identify our forward-looking statements by the words "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 outcomes and results may differ materially from what we have expressed or forecast in the forward-looking statements. Any differences could result from a variety of factors, including the following:

- Fluctuations in crude oil, natural gas and natural gas liquids prices, refining and marketing margins and margins for our chemicals business;
- Changes in our business, operations, results and prospects;
- The operation and financing of our midstream and chemicals joint ventures;
- 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, natural gas liquids, LNG and refined products;
- Inability to timely obtain or maintain permits, including those necessary for construction of LNG terminals or regasification facilities, comply with government regulations or make capital expenditures required to maintain compliance;
- Failure to complete definitive agreements and feasibility studies for, and to timely complete construction of, announced and future LNG projects and related facilities;
- 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 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.

Item 3. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

Information about market risks for the six months ended June 30, 2004, does not differ materially from that discussed under Item 7A of ConocoPhillips' Annual Report on Form 10-K for the year ended December 31, 2003.

Item 4. CONTROLS AND PROCEDURES

As of June 30, 2004, with the participation of our management, our President and Chief Executive Officer and our Executive Vice President, Finance, and Chief Financial Officer carried out an evaluation of the effectiveness of the design and operation of ConocoPhillips' disclosure controls and procedures pursuant to Rule 13a-15(b) of the Securities Exchange Act of 1934, as amended. Based upon that evaluation, our President and Chief Executive Officer and our Executive Vice President, Finance, and Chief Financial Officer concluded that our disclosure controls and procedures were operating effectively as of June 30, 2004.

During the second quarter of 2004, we implemented the first phase of the Supply Trading Analysis & Reporting (STAR) information system. STAR now handles the contracting, scheduling, and business analysis reporting for a portion of the motor fuels and heavy intermediate product business. In a future phase scheduled for early 2005, the remaining portion of these commodity streams will be moved into the system.

There have been no changes in our internal control over financial reporting, as defined in Rule 13a-15(f) of the Securities Exchange Act, that occurred subsequent to the period covered by this report that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

PART II. OTHER INFORMATION

Item 1. LEGAL PROCEEDINGS

There have been no material developments with respect to the legal proceedings previously reported in our first quarter 2004 Form 10-Q or our 2003 Annual Report on Form 10-K.

We are subject to various lawsuits and claims including, but not limited to: personal injury claims; 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 in October 1998, 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.

Item 2. CHANGES IN SECURITIES, USE OF PROCEEDS AND ISSUER PURCHASES OF EQUITY SECURITIES

ConocoPhillips

Issuer Purchases of Equity Securities

Period	Total Number of Shares Purchased*	Average Price paid per Share**	Total Number of Shares Purchased as Part of Publicly Announced Program***	Maximum Number of Shares that May Yet Be Purchased Under the Program
January 1-31, 2004	21,974	$ 65.82	—	—
February 1-29, 2004	6,668	66.97	—	—
March 1-31, 2004	6,493	69.79	—	—
Total	35,135	$ 67.53	—	—
April 1-30, 2004	3,417	$ 72.40	—	—
May 1-31, 2004	805	72.73	—	—
June 1-30, 2004	6,719	75.74	—	—
Total	10,941	$ 73.62	—	—

**Transactions represent the repurchase of common shares from company employees to pay the option exercise price and to satisfy tax withholding obligations in connection with the individual's exercise of the stock options issued to management and employees under the company's broad-based employee stock options and long-term incentive plans.*

***The average price paid per share is based upon the low and high trading prices on the New York Stock Exchange on the date of the transaction.*

****No share repurchases were made pursuant to a publicly announced plan or program.*

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

We held our annual stockholders meeting on May 5, 2004. A brief description of each proposal and the voting results follow:

A company proposal to elect five directors.

	For	Against
David L. Boren	615,885,000	14,607,678
James E. Copeland, Jr.	613,506,082	16,986,596
Kenneth M. Duberstein	618,056,232	12,436,446
Ruth R. Harkin	618,826,365	11,666,313
William R. Rhodes	618,904,131	11,588,547
J. Stapleton Roy	619,085,988	11,406,690

Those directors whose term of office continued were as follows: Richard H. Auchinleck, Norman R. Augustine, Archie W. Dunham, Larry D. Horner, Charles C. Krulak, Frank A. McPherson, J. J. Mulva, William K. Reilly, Victoria J. Tschinkel and Kathryn C. Turner.

A company proposal to ratify the appointment of Ernst & Young LLP as independent auditors for 2004.

For	614,705,170
Against	11,593,429
Abstentions	4,194,079
Broker Non-Votes	—

A company proposal to ratify the 2004 Omnibus Stock and Performance Incentive Plan.

For	465,681,246
Against	87,890,118
Abstentions	5,786,823
Broker Non-Votes	—

A shareholder proposal to place a limit on executive compensation.

For	32,068,488
Against	517,976,494
Abstentions	9,315,331
Broker Non-Votes	—

A shareholder proposal requesting a “Commonsense Executive Compensation” program.

For	48,536,538
Against	499,968,091
Abstentions	10,855,684
Broker Non-Votes	—

A shareholder proposal requesting ConocoPhillips' Board of Directors to prepare a report, at a reasonable cost and omitting proprietary information, on the potential environmental damage that would result from drilling for oil and gas in the coastal plain of the Arctic National Wildlife Refuge.

For	45,567,277
Against	447,678,362
Abstentions	66,114,674
Broker Non-Votes	—

All five nominated directors were elected and the appointment of the independent auditors and the 2004 Omnibus Stock and Performance Incentive Plan were ratified. The three shareholder proposals were not ratified.

Item 6. EXHIBITS AND REPORTS ON FORM 8-K

Exhibits

12 Computation of Ratio of Earnings to Fixed Charges.

31.1 Certification of Chief Executive Officer pursuant to Rule 13a-14(a) under the Securities Exchange Act of 1934.

31.2 Certification of Chief Financial Officer pursuant to Rule 13a-14(a) under the Securities Exchange Act of 1934.

32 Certifications pursuant to 18 U.S.C. Section 1350.

Reports on Form 8-K

During the three months ended June 30, 2004, ConocoPhillips furnished the following Current Reports on Form 8-K:

- Current Report furnished April 5, 2004, reporting Item 7 and Item 12.
- Current Report furnished April 28, 2004, reporting Item 7 and Item 12.

SIGNATURE

Pursuant to the requirements of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned thereunto duly authorized.

CONOCOPHILLIPS

/s/ Rand C. Berney

Rand C. Berney
Vice President and Controller
(Chief Accounting and Duly Authorized Officer)

August 5, 2004

[Table of Contents](#)

EXHIBIT INDEX

EXHIBITS	
12	Computation of Ratio of Earnings to Fixed Charges.
31.1	Certification of Chief Executive Officer pursuant to Rule 13a-14(a) under the Securities Exchange Act of 1934.
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32	Certifications pursuant to 18 U.S.C. Section 1350.

Exhibit 12

CONOCOPHILLIPS AND CONSOLIDATED SUBSIDIARIES
TOTAL ENTERPRISE

Computation of Ratio of Earnings to Fixed Charges

	Millions of Dollars	
	Six Months Ended June 30	
	2004	2003
	(Unaudited)	
Earnings Available for Fixed Charges		
Income from continuing operations before income taxes	**$ 6,434**	4,350
Distributions less than equity in earnings of fifty-percent-or-less-owned companies	**(235)**	(64)
Fixed charges, excluding capitalized interest*	**387**	555
	$ 6,586	4,841
Fixed Charges		
Interest and expense on indebtedness, excluding capitalized interest	$ **304**	457
Capitalized interest	**219**	151
Interest expense relating to guaranteed debt of greater-than-fifty-percent-owned companies	**—**	2
Interest portion of rental expense	**75**	84
	$ 598	694
Ratio of Earnings to Fixed Charges	**11.0**	7.0

**Includes amortization of capitalized interest totaling approximately $8 million in 2004 and $12 million in 2003.*

Earnings available for fixed charges include, if any, our equity in losses of companies owned less than fifty percent and having debt for which the company is contingently liable. Fixed charges include our proportionate share, if any, of interest relating to the contingent debt.

Earnings available for fixed charges include, if any, 100 percent of the losses of companies owned greater than fifty percent that have debt for which we are contingently liable. Fixed charges include 100 percent of interest and capitalized interest, if any, relating to the contingent debt.

Exhibit 31.1

CERTIFICATION

I, J. J. Mulva, certify that:

1. I have reviewed this quarterly report on Form 10-Q of ConocoPhillips;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant’s other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) for the registrant and have:

   (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   (b) Evaluated the effectiveness of the registrant’s disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   (c) Disclosed in this report any change in the registrant’s internal control over financial reporting that occurred during the registrant’s most recent fiscal quarter (the registrant’s fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant’s internal control over financial reporting; and

5. The registrant’s other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant’s auditors and the audit committee of the registrant’s board of directors (or persons performing the equivalent functions):

   (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant’s ability to record, process, summarize and report financial information; and

   (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant’s internal control over financial reporting.

Date: August 5, 2004

/s/ J. J. Mulva

J. J. Mulva
President and Chief Executive Officer

Exhibit 31.2

CERTIFICATION

I, John A. Carrig, certify that:

1. I have reviewed this quarterly report on Form 10-Q of ConocoPhillips;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) for the registrant and have:

   (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   (b) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   (c) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

   (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

   (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: August 5, 2004

/s/ John A. Carrig

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

Exhibit 32

CERTIFICATIONS PURSUANT TO 18 U.S.C. SECTION 1350

In connection with the Quarterly Report of ConocoPhillips (the company) on Form 10-Q for the period ended June 30, 2004, as filed with the U.S. Securities and Exchange Commission on the date hereof (the Report), each of the undersigned hereby certifies, pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, that to their knowledge:

(1) The Report fully complies with the requirements of Sections 13(a) or 15(d) of the Securities Exchange Act of 1934; and

(2) The information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the company.

Date: August 5, 2004

/s/ J. J. Mulva

J. J. Mulva
President and Chief Executive Officer

/s/ John A. Carrig

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