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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 **September 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 **333-74798 (001-[Number Applied For])**

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 690,233,100 shares of common stock, $.01 par value, outstanding at September 30, 2004.

CONOCOPHILLIPS

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PART I. FINANCIAL INFORMATION

Item 1. FINANCIAL STATEMENTS

Consolidated Income Statement **ConocoPhillips**

	Millions of Dollars			
	Three Months Ended September 30		Nine Months Ended September 30	
	2004	2003**	**2004**	2003**
Revenues				
Sales and other operating revenues*	$ **34,337**	26,105	**95,652**	78,366
Equity in earnings of affiliates	**389**	186	**980**	391
Other income	**15**	202	**212**	378
Total Revenues	**34,741**	26,493	**96,844**	79,135
Costs and Expenses				
Purchased crude oil and products	**23,100**	16,826	**63,198**	50,884
Production and operating expenses	**1,811**	1,725	**5,323**	5,225
Selling, general and administrative expenses	**525**	551	**1,502**	1,601
Exploration expenses	**205**	132	**511**	390
Depreciation, depletion and amortization	**938**	858	**2,768**	2,574
Property impairments	**12**	18	**63**	192
Taxes other than income taxes*	**4,336**	3,807	**12,878**	10,853
Accretion on discounted liabilities	**49**	39	**126**	107
Interest and debt expense	**101**	190	**405**	647
Foreign currency transaction (gains) losses	**(4)**	34	**(53)**	14
Minority interests	**8**	3	**29**	16
Total Costs and Expenses	**31,081**	24,183	**86,750**	72,503
Income from continuing operations before income taxes and subsidiary equity transactions	**3,660**	2,310	**10,094**	6,632
Gain on subsidiary equity transactions	**—**	—	**—**	28
Income from continuing operations before income taxes	**3,660**	2,310	**10,094**	6,660
Provision for income taxes	**1,649**	1,061	**4,467**	3,052
Income From Continuing Operations	**2,011**	1,249	**5,627**	3,608
Income (loss) from discontinued operations	**(5)**	57	**70**	201
Income before cumulative effect of changes in accounting principles	**2,006**	1,306	**5,697**	3,809
Cumulative effect of changes in accounting principles	**—**	—	**—**	(95)
Net Income	$ **2,006**	1,306	**5,697**	3,714
Income Per Share of Common Stock				
Basic				
Continuing operations	$ **2.91**	1.84	**8.16**	5.30
Discontinued operations	**(.01)**	.08	**.11**	.30
Before cumulative effect of changes in accounting principles	**2.90**	1.92	**8.27**	5.60
Cumulative effect of changes in accounting principles	**—**	—	**—**	(.14)
Net Income	$ **2.90**	1.92	**8.27**	5.46
Diluted				
Continuing operations	$ **2.87**	1.82	**8.06**	5.28
Discontinued operations	**(.01)**	.08	**.10**	.29
Before cumulative effect of changes in accounting principles	**2.86**	1.90	**8.16**	5.57
Cumulative effect of changes in accounting principles	**—**	—	**—**	(.14)
Net Income	$ **2.86**	1.90	**8.16**	5.43
Dividends Paid Per Share of Common Stock	$ **.43**	.40	**1.29**	1.20
Average Common Shares Outstanding (in thousands)				
Basic	**691,826**	680,689	**689,214**	680,089
Diluted	**701,716**	686,263	**698,519**	684,248
**Includes excise, value added and other similar taxes on petroleum products sales:*	*$ **4,079***	*3,580*	***12,073***	*10,115*

***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	
	September 30 2004	December 31 2003
Assets		
Cash and cash equivalents	$ **3,263**	490
Accounts and notes receivable (net of allowance of $54 million in 2004 and $43 million in 2003)	**4,389**	3,606
Accounts and notes receivable—related parties	**2,584**	1,399
Inventories	**4,334**	3,957
Prepaid expenses and other current assets	**1,094**	876
Assets of discontinued operations held for sale	**329**	864
Total Current Assets	**15,993**	11,192
Investments and long-term receivables	**7,497**	7,258
Net properties, plants and equipment	**48,701**	47,428
Goodwill	**15,078**	15,084
Intangibles	**1,102**	1,085
Other assets	**447**	408
Total Assets	$ **88,818**	82,455
Liabilities		
Accounts payable	$ **7,880**	6,598
Accounts payable—related parties	**397**	301
Notes payable and long-term debt due within one year	**1,079**	1,440
Accrued income and other taxes	**3,149**	2,676
Other accruals	**2,500**	2,817
Liabilities of discontinued operations held for sale	**163**	179
Total Current Liabilities	**15,168**	14,011
Long-term debt	**14,407**	16,340
Asset retirement obligations and accrued environmental costs	**3,842**	3,603
Deferred income taxes	**9,805**	8,565
Employee benefit obligations	**2,496**	2,445
Other liabilities and deferred credits	**2,297**	2,283
Total Liabilities	**48,015**	47,247
Minority Interests	**1,036**	842
Common Stockholders' Equity		
Common stock (2,500,000,000 shares authorized at $.01 par value)		
Issued (2004—714,934,414 shares; 2003—708,085,097 shares)		
Par value	**7**	7
Capital in excess of par	**25,823**	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	**978**	821
Unearned employee compensation	**(251)**	(200)
Retained earnings	**14,047**	9,234
Total Common Stockholders' Equity	**39,767**	34,366
Total	$ **88,818**	82,455

See Notes to Consolidated Financial Statements.

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Consolidated Statement of Cash Flows **ConocoPhillips**

	Millions of Dollars	
	Nine Months Ended September 30	
	2004	2003**
Cash Flows From Operating Activities		
Income from continuing operations	$ **5,627**	3,608
Adjustments to reconcile income from continuing operations to net cash provided by continuing operations		
Non-working capital adjustments		
Depreciation, depletion and amortization	**2,768**	2,574
Property impairments	**63**	192
Dry hole costs and leasehold impairments	**342**	169
Accretion on discounted liabilities	**126**	107
Deferred income taxes	**998**	333
Undistributed equity earnings	**(541)**	(191)
Gain on asset dispositions	**(82)**	(226)
Other	**105**	(126)
Working capital adjustments*		
Increase (decrease) in aggregate balance of accounts receivable sold	**(600)**	48
Increase in other accounts and notes receivable	**(1,224)**	(60)
Increase in inventories	**(373)**	(220)
Decrease (increase) in prepaid expenses and other current assets	**(87)**	287
Increase in accounts payable	**1,374**	314
Increase in taxes and other accruals	**299**	334
Net cash provided by continuing operations	**8,795**	7,143
Net cash provided by (used in) discontinued operations	**(33)**	181
Net Cash Provided by Operating Activities	**8,762**	7,324
Cash Flows From Investing Activities		
Cash consolidated from adoption and application of FIN 46	**11**	225
Capital expenditures and investments, including dry hole costs	**(4,659)**	(4,385)
Proceeds from asset dispositions	**1,427**	1,504
Long-term advances to affiliates and other investments	**(5)**	2
Net cash used in continuing operations	**(3,226)**	(2,654)
Net cash used in discontinued operations	**(2)**	(59)
Net Cash Used in Investing Activities	**(3,228)**	(2,713)
Cash Flows From Financing Activities		
Issuance of debt	**290**	294
Repayment of debt	**(2,594)**	(4,086)
Issuance of company common stock	**269**	53
Dividends paid on common stock	**(886)**	(815)
Other	**117**	75
Net cash used in continuing operations	**(2,804)**	(4,479)
Net Cash Used in Financing Activities	**(2,804)**	(4,479)
Effect of Exchange Rate Changes on Cash and Cash Equivalents	**43**	44
Net Change in Cash and Cash Equivalents	**2,773**	176
Cash and cash equivalents at beginning of period	**490**	307
Cash and Cash Equivalents at End of Period	$ **3,263**	483

**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 of Financial Condition and Results of Operations 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 September 30		Nine Months Ended September 30	
	2004	2003	**2004**	2003*
Net income, as reported	$ **2,006**	1,306	**5,697**	3,714
Add: Stock-based employee compensation expense included in reported net income, net of related tax effects	**27**	7	**66**	25
Deduct: Total stock-based employee compensation expense determined under fair-value-based method for all awards, net of related tax effects	**29**	14	**74**	48
Pro forma net income	$ **2,004**	1,299	**5,689**	3,691
Earnings per share:				
Basic—as reported	$ **2.90**	1.92	**8.27**	5.46
Basic—pro forma	**2.90**	1.91	**8.25**	5.43
Diluted—as reported	**2.86**	1.90	**8.16**	5.43
Diluted—pro forma	**2.86**	1.89	**8.14**	5.39

**Restated for adoption of FIN 46 and reclassified to conform to current year presentation.*

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. In the fourth quarter of 2003, also retroactive to January 1, 2003, we made an $18 million adjustment to Cumulative Effect of Changes in Accounting Principles related to our adoption of FIN 46. Accordingly, our financial statements for the nine months of 2003 have been restated from amounts previously reported in the financial statements included in our Form 10-Q for the quarter ended September 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 cash is received by us. In September 2003, the first ship was delivered to its owner and the second ship is scheduled for delivery to its owner in 2005. 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 nine 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, we recorded a net after-tax gain of approximately $116 million in the nine-month 2004 period. Discussions are under way with potential buyers for the remaining marketing assets held for sale.

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

	Millions of Dollars			
	Three Months Ended September 30		Nine Months Ended September 30	
	2004	2003	**2004**	2003
Sales and other operating revenues from discontinued operations	$ **105**	2,046	**1,024**	6,599
Income (loss) from discontinued operations before-tax	**$ (7)**	101	**96**	333
Income taxes	**(2)**	44	**26**	132
Income (loss) from discontinued operations	**$ (5)**	57	**70**	201

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

	Millions of Dollars	
	September 30 2004	December 31 2003
Assets		
Net properties, plants and equipment	**$ 328**	857
Other assets	**1**	7
Assets of discontinued operations	**$ 329**	864
Liabilities		
Deferred income taxes, other liabilities and deferred credits	**$ 163**	179
Liabilities of discontinued operations	**$ 163**	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	
		September 30 2004	December 31 2003
Crude oil and petroleum products	**$**	**3,854**	3,467
Materials, supplies and other		**480**	490
	$	**4,334**	3,957

Inventories valued on a last-in, first-out (LIFO) basis totaled $3,665 million and $3,224 million at September 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 $3,629 million and $1,421 million at September 30, 2004, and December 31, 2003, respectively.

Note 7—Properties, Plants and Equipment

Properties, plants and equipment included the following:

		Millions of Dollars	
		September 30 2004	December 31 2003
Properties, plants and equipment	**$**	**65,869**	61,839
Less: accumulated depreciation, depletion and amortization		**17,168**	14,411
	$	**48,701**	47,428

E&P properties, plants and equipment at September 30, 2004, and December 31, 2003, included approximately $9.7 billion and $10.5 billion, respectively, of mineral rights to extract oil and gas, net of accumulated depletion.

Property Impairments—In the third quarter and first nine months of 2004, we recorded property impairments related to planned dispositions in our Midstream, Exploration and Production (E&P) and Refining and Marketing (R&M) segments. In the third quarter and first nine 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 September 30		Nine Months Ended September 30	
	2004	2003	**2004**	2003
Exploration and Production	**$ 2**	18	**10**	187
Midstream	**—**	—	**36**	—
Refining and Marketing	**10**	—	**17**	—
Corporate and Other	**—**	—	**—**	5
	$ 12	18	**63**	192

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 $316 million was accrued in the first nine months of 2003, including $91 million in the third 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 $316 million accrued in the first nine months of 2003, $109 million was reflected as a purchase price adjustment in the consolidated financial statements and $207 million was reflected in selling, general and administrative expense and production and operating expense. Included in the total accruals of $316 million was a $92 million expense related to pension and other postretirement benefits. In the first nine months of 2004, we recorded additional accruals totaling $34 million, of which $28 million was reflected in the consolidated financial statements as selling, general and administrative expense and production and operating expense, and $6 million was reflected as foreign currency translation adjustment. Included in the total accruals of $34 million was a $4 million expense related to pension and postretirement benefits. A roll-forward of activity during the first nine months of 2004 is provided below for the non-pension 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			
		Nine Months 2004		
	Reserve at December 31, 2003	Accrual	Payments	Reserve at September 30, 2004
Conoco	$ 83	(8)	(58)	17
Phillips	164	38	(128)	74
Total	$ 247	30	(186)	91

The ending accrual balance at September 30, 2004, is expected to be extinguished within one year, except for $57 million, which is classified as long-term. Approximately 950 employees were terminated during the first nine months of 2004, and essentially all 3,950 employee terminations under the restructuring program have now been completed.

Note 9—Debt

At September 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 September 30, 2004, we had no debt outstanding under these credit facilities, but had $1 billion of commercial paper outstanding, compared with $709 million of commercial paper 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.

On October 12, 2004, we replaced the four bank credit facilities noted above with two facilities totaling $5 billion and increased our commercial paper program from $4 billion to $5 billion. The facilities include a $2.5 billion four-year facility expiring in October 2008 and a $2.5 billion five-year facility expiring in October 2009. Both facilities are available for use as direct bank borrowings or as support for our $5 billion commercial paper program. In addition, the five-year facility may be used to support issuances of letters of credit totaling up to $750 million. The facilities are syndicated among 40 financial institutions and do not contain any material adverse change provisions or any covenants requiring maintenance of specified financial ratios or ratings. The credit agreements do contain a cross-default provision relating to our, or any of our consolidated subsidiaries', failure to pay principal or interest on other debt obligations of $200 million or more.

During the first nine months of 2004, we paid off the $1,350 million aggregate principal amount of our 5.90% Notes due 2004 when they matured in April, and in August, we redeemed the $1,150 million aggregate principal amount of our 8.5% Notes due 2005 at a premium of $58 million plus accrued interest.

On October 14, 2004, we amended and restated the ConocoPhillips Savings Plan term loan. This loan will require repayment in semi-annual installments beginning in 2009 and continuing through 2015. Under this loan, any participating bank in the syndicate of lenders may cease to participate on December 4, 2009, by giving not less than 180 days' prior notice to the ConocoPhillips Savings Plan and the company. At September 30, 2004, $259 million was outstanding under this term loan.

Note 10—Contingencies

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 September 30, 2004, ConocoPhillips' balance sheet included a total environmental accrual of $1,148 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 September 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 non-recourse 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 $420 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 non-recourse upon startup and completion certification.

Guarantees of Joint-Venture Debt

- At September 30, 2004, we had guarantees of about $275 million outstanding for our portion of joint-venture debt obligations, which have terms of up to 20 years. Included in these outstanding guarantees was $95 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 September 30, 2004, was less than $1 million.

- We have other guarantees totaling $310 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 September 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 nine 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 September 30, 2004, was $240 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 were $121 million of environmental accruals for known contamination that is included in asset retirement obligations and accrued environmental costs at September 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 September 30, 2004, was $236 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 September 30		Nine Months Ended September 30	
	2004	2003	**2004**	2003
Net income	**$ 2,006**	1,306	**5,697**	3,714
After-tax changes in:				
Minimum pension liability adjustment	**—**	—	**(1)**	5
Foreign currency translation adjustments	**132**	59	**156**	408
Unrealized gain (loss) on securities	**—**	—	**—**	2
Hedging activities	**(3)**	9	**2**	15
	$ 2,135	1,374	**5,854**	4,144

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

	Millions of Dollars	
	September 30 2004	December 31 2003
Minimum pension liability adjustment	**$ (69)**	(68)
Foreign currency translation adjustments	**1,041**	885
Unrealized gain on securities	**5**	5
Deferred net hedging gain	**1**	(1)
	$ 978	821

Note 13—Supplemental Cash Flow Information

	Millions of Dollars	
	Nine Months Ended September 30	
	2004	2003
Non-Cash Investing and Financing Activities		
Increase in properties, plants and equipment (PP&E) in exchange for related increase in asset retirement obligations associated with the initial implementation of SFAS No. 143	$ —	1,229
Increase in PP&E from incurrence of asset retirement obligations due to repeal of Norway Removal Grant Act	$ —	336
Increase in PP&E 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	$ **324**	515
Income taxes	**2,791**	1,686

Note 14—Sales of Receivables

At September 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 September 30, 2004, and December 31, 2003, the QSPE had issued beneficial interests to the bank-sponsored entities of $600 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 $2.4 billion at September 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		**6,075**	19,201
Cash collections remitted		**(6,675)**	(19,324)
Receivables sold at September 30	$	**600**	1,200
Discounts and other fees paid on revolving balances	$	**5**	15

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 September 30, 2004, we had no receivables outstanding under similar arrangements.

Note 15—Employee Benefit Plans

Pension and Postretirement Plans

Three Months Ended		Millions of Dollars					
		Pension Benefits				Other Benefits	
		September 30				September 30	
		2004		2003		**2004**	2003
		U.S.	**Int'l.**	U.S.	Int'l.		
Components of Net Periodic Benefit Cost							
Service cost	$	**38**	**18**	32	14	**6**	4
Interest cost		**44**	**28**	50	20	**15**	17
Expected return on plan assets		**(26)**	**(23)**	(22)	(17)	**—**	—
Amortization of prior service cost		**1**	**2**	1	1	**4**	5
Recognized net actuarial loss		**13**	**9**	17	4	**2**	1
Net periodic benefit costs	$	**70**	**34**	78	22	**27**	27

Nine Months Ended		Millions of Dollars					
		Pension Benefits				Other Benefits	
		September 30				September 30	
		2004		2003		**2004**	2003
		U.S.	**Int'l.**	U.S.	Int'l.		
Components of Net Periodic Benefit Cost							
Service cost	$	**113**	**52**	98	40	**17**	12
Interest cost		**131**	**83**	148	56	**44**	46
Expected return on plan assets		**(78)**	**(68)**	(67)	(49)	**—**	—
Amortization of prior service cost		**3**	**5**	3	3	**14**	14
Recognized net actuarial loss		**39**	**29**	52	11	**7**	4
Net periodic benefit costs	$	**208**	**101**	234	61	**82**	76

We recognized pension settlement losses of $9 million and $93 million in the first nine months of 2004 and 2003, respectively, due to high levels of lump-sum elections by new retirees in certain plans. Of these amounts, $1 million and $11 million were recognized in the third quarters of 2004 and 2003, respectively.

In December 2003, the Medicare Prescription Drug, Improvement, and Modernization Act of 2003 (Act) was signed into law. The Act introduced a prescription drug benefit under Medicare (Medicare Part D), as well as a federal subsidy to sponsors of retiree health care benefit plans that provide a benefit that is at least actuarially equivalent to Medicare Part D. In May 2004, the FASB released Staff Position 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 have determined, based on available regulatory guidance, that the prescription drug benefits provided by our retiree medical plan are not actuarially equivalent to the Medicare Part D benefit. Consequently, the federal subsidy will have no impact on the calculation of our medical plan liability or expense. We continue to evaluate the impact of the legislation on our benefit plan design.

In our second quarter 2004 Report on Form 10-Q, we disclosed that our 2004 contributions were expected to be approximately $425 million to our domestic qualified and non-qualified benefit plans and $125 million to our international qualified and non-qualified benefit plans. We now anticipate contributing $440 million to our domestic plans and $135 million to our international plans in 2004.

Note 16—Related Party Transactions

Significant transactions with related parties were:

	Millions of Dollars			
	Three Months Ended September 30		Nine Months Ended September 30	
	2004	2003	**2004**	2003
Operating revenues (a)	**$ 1,365**	898	**3,720**	2,907
Purchases (b)	**916**	821	**2,876**	2,526
Operating expenses and selling, general and administrative expenses (c)	**160**	148	**494**	406
Net interest (income) expense (d)	**2**	(6)	**(13)**	(17)

(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.

(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 September 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 September 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.

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Analysis of Results by Operating Segment

	Millions of Dollars			
	Three Months Ended September 30		Nine Months Ended September 30	
	2004	2003	**2004**	2003
Sales and Other Operating Revenues				
E&P				
United States	$ **6,138**	4,442	**17,351**	14,293
International	**3,429**	2,983	**11,136**	9,421
Intersegment eliminations-U.S.	**(652)**	(567)	**(2,011)**	(1,836)
Intersegment eliminations-international	**(692)**	(775)	**(2,651)**	(2,326)
E&P	**8,223**	6,083	**23,825**	19,552
Midstream				
Total sales	**900**	1,015	**2,839**	3,524
Intersegment eliminations	**(175)**	(375)	**(712)**	(1,063)
Midstream	**725**	640	**2,127**	2,461
R&M				
United States	**19,005**	14,219	**51,823**	41,947
International	**6,449**	5,165	**18,040**	14,550
Intersegment eliminations-U.S.	**(98)**	(54)	**(290)**	(292)
Intersegment eliminations-international	**(24)**	—	**(25)**	(12)
R&M	**25,332**	19,330	**69,548**	56,193
Chemicals	**4**	4	**11**	10
Emerging Businesses	**45**	42	**130**	136
Corporate and Other	**8**	6	**11**	14
Consolidated Sales and Other Operating Revenues	$ **34,337**	26,105	**95,652**	78,366
Net Income (Loss)				
E&P				
United States	$ **701**	546	**2,007**	1,883
International	**719**	421	**2,024**	1,428
Total E&P	**1,420**	967	**4,031**	3,311
Midstream	**38**	31	**135**	87
R&M				
United States	**505**	416	**1,642**	814
International	**203**	69	**348**	256
Total R&M	**708**	485	**1,990**	1,070
Chemicals	**81**	7	**166**	(4)
Emerging Businesses	**(27)**	(18)	**(78)**	(75)
Corporate and Other	**(214)**	(166)	**(547)**	(675)
Consolidated Net Income	$ **2,006**	1,306	**5,697**	3,714

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	Millions of Dollars	
	September 30 2004	December 31 2003
Total Assets		
E&P		
United States	**$ 15,494**	15,262
International	**24,452**	22,458
Goodwill	**11,178**	11,184
Total E&P	**51,124**	48,904
Midstream	**1,383**	1,736
R&M		
United States	**18,941**	17,172
International	**5,380**	5,020
Goodwill	**3,900**	3,900
Total R&M	**28,221**	26,092
Chemicals	**2,187**	2,094
Emerging Businesses	**921**	843
Corporate and Other	**4,982**	2,786
Consolidated Total Assets	**$ 88,818**	82,455

Note 18—Income Taxes

Our effective tax rates for the third quarter and first nine months of 2004 were 45 percent and 44 percent, respectively, compared with 46 percent for the same periods a year ago. There were not any material changes in the effective tax rate between the third quarter of 2004 and the third quarter 2003. The reduction in the effective tax rate for the first nine 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. 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

On July 8, 2004, we retired the minority interest in Conoco Corporate Holdings L.P. 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.

Note 20—New Accounting Standards

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 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 revised Statement does not change the measurement or recognition of employee benefit plans. We adopted the provisions of the Statement 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 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 03-6, "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 in this report.

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. In September 2004, the FASB issued FASB Staff Position No. 142-2, which confirmed that the scope exception in paragraph 8(b) of SFAS No. 142 extends to the disclosure provision for oil-and-gas producing entities. The effective date for this FASB Staff Position is October 1, 2004. See Note 7—Properties, Plants and Equipment for additional information.

Note 21—Subsequent Events

On September 29, 2004, we made a joint announcement with LUKOIL, an international integrated oil and gas company headquartered in Russia, of an agreement to form a broad-based strategic alliance, whereby we would become a strategic equity investor in LUKOIL. Together, we also announced our intention to form a joint venture between the two companies to develop resources in the northern part of Russia's Timan-Pechora oil and gas province and the intention of the two companies to jointly seek the right to develop the West Qurna oil field in Iraq.

In the announcement, we disclosed that we were the successful bidder in an auction of 7.6 percent of LUKOIL's authorized and issued ordinary shares held by the Russian government for a price of $1,988 million, or $30.76 per share. The transaction closed on October 7, 2004. We expect, however, to increase our ownership in LUKOIL to approximately 10 percent by the end of 2004 if market conditions permit. Under the Shareholder Agreement between the two companies, we will have proportional membership on the LUKOIL Board of Directors (Board) and LUKOIL will propose for shareholder approval amendments to its corporate charter that will require unanimous Board consent for certain key decisions. We expect that one of our nominees will be elected to the LUKOIL Board in early 2005. In addition, the Shareholder Agreement allows us to increase our ownership interest in LUKOIL to 20 percent and limits our ability to sell our LUKOIL shares for a period of four years except in certain circumstances.

Under the terms of the joint-venture arrangements, we will pay an acquisition price to LUKOIL of approximately $370 million for a 30 percent economic interest in the joint venture to develop oil and gas resources in the northern part of Russia's Timan-Pechora province, together with an additional payment for LUKOIL's 30 percent share of working capital and its 30 percent share of capital investments in the joint-venture fields from January 1, 2004. Under the joint-venture arrangements, we will have a 50 percent voting interest. The exact amount of the acquisition price will be established at closing, which is anticipated in the first quarter of 2005.

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Supplementary Information—Condensed Consolidating Financial Information

We have various cross guarantees among ConocoPhillips, ConocoPhillips Holding Company, and ConocoPhillips Company with respect to publicly held debt securities. 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.

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Income Statement	ConocoPhillips	ConocoPhillips Holding Company	ConocoPhillips Company	All Other Subsidiaries	Consolidating Adjustments	Total Consolidated
	Millions of Dollars					
	Three Months Ended September 30, 2004					
Revenues						
Sales and other operating revenues	$ —	—	23,678	10,659	—	34,337
Equity in earnings of affiliates	2,013	1,986	1,580	295	(5,485)	389
Other income	—	—	(3)	18	—	15
Intercompany revenues	16	142	447	2,061	(2,666)	—
Total Revenues	2,029	2,128	25,702	13,033	(8,151)	34,741
Costs and Expenses						
Purchased crude oil and products	—	—	19,646	5,715	(2,261)	23,100
Production and operating expenses	—	—	1,056	763	(8)	1,811
Selling, general and administrative expenses	3	—	315	205	2	525
Exploration expenses	—	—	4	201	—	205
Depreciation, depletion and amortization	—	—	318	620	—	938
Property impairments	—	—	10	2	—	12
Taxes other than income taxes	—	—	1,712	2,624	—	4,336
Accretion on discounted liabilities	—	—	13	36	—	49
Interest and debt expense	21	100	296	83	(399)	101
Foreign currency transaction losses (gains)	—	—	—	(4)	—	(4)
Minority interests	—	—	—	8	—	8
Total Costs and Expenses	24	100	23,370	10,253	(2,666)	31,081
Income from continuing operations before income taxes and subsidiary equity transactions	2,005	2,028	2,332	2,780	(5,485)	3,660
Gain on subsidiary equity transactions	—	—	—	—	—	—
Income from continuing operations before income taxes	2,005	2,028	2,332	2,780	(5,485)	3,660
Provision for income taxes	(6)	15	367	1,273	—	1,649
Income from continuing operations	2,011	2,013	1,965	1,507	(5,485)	2,011
Income (loss) from discontinued operations	(5)	(5)	(5)	3	7	(5)
Income before cumulative effect of changes in accounting principles	2,006	2,008	1,960	1,510	(5,478)	2,006
Cumulative effect of changes in accounting principles	—	—	—	—	—	—
Net Income	$ 2,006	2,008	1,960	1,510	(5,478)	2,006

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Income Statement	ConocoPhillips	ConocoPhillips Holding Company	ConocoPhillips Company	All Other Subsidiaries	Consolidating Adjustments	Total Consolidated
	Millions of Dollars					
	Three Months Ended September 30, 2003					
Revenues						
Sales and other operating revenues	$ —	—	16,938	9,167	—	26,105
Equity in earnings of affiliates	1,244	1,212	1,036	155	(3,461)	186
Other income	—	—	(10)	212	—	202
Intercompany revenues	33	150	604	1,152	(1,939)	—
Total Revenues	1,277	1,362	18,568	10,686	(5,400)	26,493
Costs and Expenses						
Purchased crude oil and products	—	—	13,568	4,857	(1,599)	16,826
Production and operating expenses	—	—	922	839	(36)	1,725
Selling, general and administrative expenses	4	—	322	228	(3)	551
Exploration expenses	—	—	42	90	—	132
Depreciation, depletion and amortization	—	—	295	563	—	858
Property impairments	—	—	16	2	—	18
Taxes other than income taxes	—	—	1,642	2,165	—	3,807
Accretion on discounted liabilities	—	—	12	27	—	39
Interest and debt expense	27	99	317	48	(301)	190
Foreign currency transaction losses (gains)	—	—	15	19	—	34
Minority interests	—	—	—	3	—	3
Total Costs and Expenses	31	99	17,151	8,841	(1,939)	24,183
Income from continuing operations before income taxes and subsidiary equity transactions	1,246	1,263	1,417	1,845	(3,461)	2,310
Gain on subsidiary equity transactions	—	—	—	—	—	—
Income from continuing operations before income taxes	1,246	1,263	1,417	1,845	(3,461)	2,310
Provision for income taxes	(3)	19	224	821	—	1,061
Income from continuing operations	1,249	1,244	1,193	1,024	(3,461)	1,249
Income from discontinued operations	57	57	57	34	(148)	57
Income before cumulative effect of changes in accounting principles	1,306	1,301	1,250	1,058	(3,609)	1,306
Cumulative effect of changes in accounting principles	—	—	—	—	—	—
Net Income	$ 1,306	1,301	1,250	1,058	(3,609)	1,306

Income Statement	Millions of Dollars Nine Months Ended September 30, 2004 ConocoPhillips	ConocoPhillips Holding Company	ConocoPhillips Company	All Other Subsidiaries	Consolidating Adjustments	Total Consolidated
Revenues						
Sales and other operating revenues	$ —	—	64,138	31,514	—	95,652
Equity in earnings of affiliates	5,624	5,493	3,986	784	(14,907)	980
Other income	—	—	48	164	—	212
Intercompany revenues	60	428	1,242	5,075	(6,805)	—
Total Revenues	5,684	5,921	69,414	37,537	(21,712)	96,844
Costs and Expenses						
Purchased crude oil and products	—	—	52,648	16,374	(5,824)	63,198
Production and operating expenses	—	1	2,947	2,405	(30)	5,323
Selling, general and administrative expenses	7	—	963	539	(7)	1,502
Exploration expenses	—	—	54	457	—	511
Depreciation, depletion and amortization	—	—	835	1,933	—	2,768
Property impairments	—	—	17	46	—	63
Taxes other than income taxes	—	—	4,633	8,245	—	12,878
Accretion on discounted liabilities	—	—	32	94	—	126
Interest and debt expense	65	228	878	178	(944)	405
Foreign currency transaction losses (gains)	—	—	1	(54)	—	(53)
Minority interests	—	—	—	29	—	29
Total Costs and Expenses	72	229	63,008	30,246	(6,805)	86,750
Income from continuing operations before income taxes and subsidiary equity transactions	5,612	5,692	6,406	7,291	(14,907)	10,094
Gain on subsidiary equity transactions	—	—	—	—	—	—
Income from continuing operations before income taxes	5,612	5,692	6,406	7,291	(14,907)	10,094
Provision for income taxes	(15)	68	974	3,440	—	4,467
Income from continuing operations	5,627	5,624	5,432	3,851	(14,907)	5,627
Income from discontinued operations	70	70	70	93	(233)	70
Income before cumulative effect of changes in accounting principles	5,697	5,694	5,502	3,944	(15,140)	5,697
Cumulative effect of changes in accounting principles	—	—	—	—	—	—
Net Income	$ 5,697	5,694	5,502	3,944	(15,140)	5,697

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Income Statement	ConocoPhillips	ConocoPhillips Holding Company	ConocoPhillips Company	All Other Subsidiaries	Consolidating Adjustments	Total Consolidated
	Millions of Dollars					
	Nine Months Ended September 30, 2003					
Revenues						
Sales and other operating revenues	$ —	—	49,692	28,674	—	78,366
Equity in earnings of affiliates	3,591	3,484	3,138	375	(10,197)	391
Other income	—	—	74	304	—	378
Intercompany revenues	108	450	2,380	3,896	(6,834)	—
Total Revenues	3,699	3,934	55,284	33,249	(17,031)	79,135
Costs and Expenses						
Purchased crude oil and products	—	—	42,142	14,531	(5,789)	50,884
Production and operating expenses	—	—	2,873	2,477	(125)	5,225
Selling, general and administrative expenses	9	—	1,022	582	(12)	1,601
Exploration expenses	—	—	101	289	—	390
Depreciation, depletion and amortization	—	—	870	1,704	—	2,574
Property impairments	—	—	42	150	—	192
Taxes other than income taxes	—	—	3,339	7,514	—	10,853
Accretion on discounted liabilities	—	—	25	82	—	107
Interest and debt expense	92	283	996	184	(908)	647
Foreign currency transaction losses (gains)	—	—	(2)	16	—	14
Minority interests	—	—	—	16	—	16
Total Costs and Expenses	101	283	51,408	27,545	(6,834)	72,503
Income from continuing operations before income taxes and subsidiary equity transactions	3,598	3,651	3,876	5,704	(10,197)	6,632
Gain on subsidiary equity transactions	—	—	—	28	—	28
Income from continuing operations before income taxes	3,598	3,651	3,876	5,732	(10,197)	6,660
Provision for income taxes	(10)	60	446	2,556	—	3,052
Income from continuing operations	3,608	3,591	3,430	3,176	(10,197)	3,608
Income from discontinued operations	201	201	201	102	(504)	201
Income before cumulative effect of changes in accounting principles	3,809	3,792	3,631	3,278	(10,701)	3,809
Cumulative effect of changes in accounting principles	(95)	(95)	(95)	(255)	445	(95)
Net Income	$ 3,714	3,697	3,536	3,023	(10,256)	3,714

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Balance Sheet	ConocoPhillips	ConocoPhillips Holding Company	ConocoPhillips Company	All Other Subsidiaries	Consolidating Adjustments	Total Consolidated
	Millions of Dollars					
	At September 30, 2004					
Assets						
Cash and cash equivalents	$ 1	—	2,761	501	—	3,263
Accounts and notes receivable	1,775	—	13,331	14,479	(22,612)	6,973
Inventories	—	—	3,053	1,281	—	4,334
Prepaid expenses and other current assets	22	23	375	674	—	1,094
Assets of discontinued operations held for sale	—	—	239	90	—	329
Total Current Assets	1,798	23	19,759	17,025	(22,612)	15,993
Investments and long-term receivables	34,758	42,709	37,345	17,039	(124,354)	7,497
Net properties, plants and equipment	—	—	16,209	32,492	—	48,701
Goodwill	—	—	15,078	—	—	15,078
Intangibles	—	—	793	309	—	1,102
Other assets	14	—	143	290	—	447
Total Assets	$ 36,570	42,732	89,327	67,155	(146,966)	88,818
Liabilities and Stockholders' Equity						
Accounts payable	$ 5	143	20,135	10,606	(22,612)	8,277
Notes payable and long-term debt due within one year	1,000	—	58	21	—	1,079
Accrued income and other taxes	(3)	—	404	2,748	—	3,149
Other accruals	45	86	998	1,371	—	2,500
Liabilities of discontinued operations held for sale	—	—	147	16	—	163
Total Current Liabilities	1,047	229	21,742	14,762	(22,612)	15,168
Long-term debt	1,997	2,909	5,236	4,265	—	14,407
Asset retirement obligations and accrued environmental costs	—	—	997	2,845	—	3,842
Deferred income taxes	41	(77)	3,144	6,705	(8)	9,805
Employee benefit obligations	—	—	1,848	648	—	2,496
Other liabilities and deferred credits	7	6,286	25,424	21,527	(50,947)	2,297
Total Liabilities	3,092	9,347	58,391	50,752	(73,567)	48,015
Minority interests	—	(12)	5	1,043	—	1,036
Retained earnings	7,508	7,159	14,200	12,380	(27,200)	14,047
Other stockholders' equity	25,970	26,238	16,731	2,980	(46,199)	25,720
Total	$ 36,570	42,732	89,327	67,155	(146,966)	88,818

Balance Sheet	ConocoPhillips	ConocoPhillips Holding Company	ConocoPhillips Company	All Other Subsidiaries	Consolidating Adjustments	Total Consolidated
	Millions of Dollars					
	At December 31, 2003					
Assets						
Cash and cash equivalents	$ —	—	268	222	—	490
Accounts and notes receivable	1,185	—	10,893	13,951	(21,024)	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	7	14,719	16,297	(21,024)	11,192
Investments and long-term receivables	29,640	37,922	37,656	16,604	(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	64,510	(135,588)	82,455
Liabilities and Stockholders' Equity						
Accounts payable	$ —	2	19,371	8,550	(21,024)	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	12,012	(21,024)	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	47,097	(71,460)	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	64,510	(135,588)	82,455

Statement of Cash Flows	ConocoPhillips	ConocoPhillips Holding Company	ConocoPhillips Company	All Other Subsidiaries	Consolidating Adjustments	Total Consolidated
	Millions of Dollars					
	Nine Months Ended September 30, 2004					
Cash Flows From Operating Activities						
Net cash provided by (used in) continuing operations	$ (241)	(166)	5,944	4,136	(878)	8,795
Net cash provided by (used in) discontinued operations	—	—	(208)	175	—	(33)
Net Cash Provided by (Used in) Operating Activities	(241)	(166)	5,736	4,311	(878)	8,762
Cash Flows From Investing Activities						
Cash consolidated from adoption of FIN 46	—	—	—	11	—	11
Capital expenditures and investments, including dry holes	—	—	(1,290)	(3,489)	120	(4,659)
Proceeds from asset dispositions	—	—	1,159	469	(201)	1,427
Long-term advances to affiliates and other investments	573	1,198	(1,471)	(287)	(18)	(5)
Net cash provided by (used in) continuing operations	573	1,198	(1,602)	(3,296)	(99)	(3,226)
Net cash used in discontinued operations	—	—	(2)	—	—	(2)
Net Cash Provided by (Used in) Investing Activities	573	1,198	(1,604)	(3,296)	(99)	(3,228)
Cash Flows From Financing Activities						
Issuance of debt	288	1,676	786	79	(2,539)	290
Repayment of debt	—	(2,708)	(2,425)	(17)	2,556	(2,594)
Issuance of company common stock	269	—	—	—	—	269
Dividends paid on common stock	(886)	—	—	(878)	878	(886)
Other	(2)	—	—	37	82	117
Net Cash Used in Financing Activities	(331)	(1,032)	(1,639)	(779)	977	(2,804)
Effect of Exchange Rate Changes on Cash and Cash Equivalents	—	—	—	43	—	43
Net Change in Cash and Cash Equivalents	1	—	2,493	279	—	2,773
Cash and cash equivalents at beginning of year	—	—	268	222	—	490
Cash and Cash Equivalents at End of Period	$ 1	—	2,761	501	—	3,263

Statement of Cash Flows	Millions of Dollars					
	Nine Months Ended September 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	$ 7,876	(792)	3,911	(666)	(3,186)	7,143
Net cash provided by (used in) discontinued operations	—	—	(75)	256	—	181
Net Cash Provided by (Used in) Operating Activities	7,876	(792)	3,836	(410)	(3,186)	7,324
Cash Flows From Investing Activities						
Cash consolidated from adoption of FIN 46	—	—	—	225	—	225
Capital expenditures and investments, including dry holes	—	(44)	(3,378)	(3,368)	2,405	(4,385)
Proceeds from asset dispositions	3	—	552	952	(3)	1,504
Long-term advances to affiliates and other investments	(6,223)	27	(5,770)	(266)	12,234	2
Net cash used in continuing operations	(6,220)	(17)	(8,596)	(2,457)	14,636	(2,654)
Net cash provided by (used in) discontinued operations	—	—	(76)	17	—	(59)
Net Cash Used in Investing Activities	(6,220)	(17)	(8,672)	(2,440)	14,636	(2,713)
Cash Flows From Financing Activities						
Issuance of debt	—	2,098	6,524	3,906	(12,234)	294
Repayment of debt	(894)	(500)	(791)	(1,901)	—	(4,086)
Issuance of company common stock	53	—	—	—	—	53
Dividends paid on common stock	(815)	(789)	(789)	(1,608)	3,186	(815)
Other	—	—	33	2,444	(2,402)	75
Net Cash Provided by (Used in) Financing Activities	(1,656)	809	4,977	2,841	(11,450)	(4,479)
Effect of Exchange Rate Changes on Cash and Cash Equivalents	—	—	(2)	46	—	44
Net Change in Cash and Cash Equivalents	—	—	139	37	—	176
Cash and cash equivalents at beginning of year	—	—	116	191	—	307
Cash and Cash Equivalents at End of Period	$ —	—	255	228	—	483

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 65.

RESULTS OF OPERATIONS

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

Business Environment and Executive Overview

Favorable market conditions contributed to a strong financial performance in the third quarter and first nine months of 2004. Net income in the third quarter of 2004 was $2,006 million, while cash from operations totaled $4,413 million. This, combined with proceeds from asset sales of $73 million, allowed us to fund our capital expenditures of $1,594 million, pay common stock dividends of $296 million, and increase our cash balance by $2,459 million. For the first nine months of 2004, net income was $5,697 million, cash from operations totaled $8,762 million, and proceeds from asset sales amounted to $1,427 million. Capital expenditures totaled $4,659 million, common stock dividends paid were $886 million, debt reduction totaled $2,294 million, and cash increased by $2,773 million.

Our Exploration and Production segment had net income of $1,420 million in the third quarter of 2004, compared with $1,354 million in the second quarter of 2004 and $967 million in the third quarter of 2003. Industry crude oil prices continued to rise in the third quarter of 2004, averaging $43.86 per barrel for West Texas Intermediate. The upward trend was primarily due to strong global consumption associated with the economic recovery, hurricane activity disrupting production in the U.S. Gulf of Mexico, risk of oil supply disruptions in Iraq and other producing countries, and strong U.S. refining demand. Industry U.S. natural gas prices declined slightly in the third quarter of 2004, compared with the second quarter of 2004, averaging about $5.75 per thousand cubic feet for Henry Hub. Natural gas prices declined in the third quarter due to mild summer weather in the U.S. and relatively high natural gas inventory levels.

Our Refining and Marketing segment had net income of $708 million in the third quarter of 2004, compared with $818 million in the second quarter of 2004 and $485 million in the third quarter of 2003. Industry U.S. refining margins declined in the third quarter of 2004 from the exceptionally high levels experienced in the second quarter, primarily due to an increase in supply from U.S. refineries, increased gasoline imports, restoration of inventory levels, and alleviation of concerns regarding refined product supply availability that were associated with the implementation of more stringent gasoline specifications. Industry U.S. marketing margins in the third quarter of 2004 declined from second quarter levels, largely because wholesale and retail prices did not rise as rapidly as gasoline spot market prices, which rose as a consequence of the increase in crude oil prices.

At September 30, 2004, our debt-to-capital ratio was 28 percent, compared with 29 percent at June 30, 2004, and 34 percent at December 31, 2003. Although we made a priority of using funds available after paying dividends and capital spending to reduce debt during the first six months of 2004, in the third quarter we began accumulating cash in anticipation of the LUKOIL transaction. See the "Outlook" section for additional information on the LUKOIL transaction.

Consolidated Results

	Millions of Dollars			
	Three Months Ended September 30		Nine Months Ended September 30	
	2004	2003	**2004**	2003*
Income from continuing operations	**$ 2,011**	1,249	**5,627**	3,608
Income (loss) from discontinued operations	**(5)**	57	**70**	201
Cumulative effect of accounting changes	**—**	—	**—**	(95)
Net income	**$ 2,006**	1,306	**5,697**	3,714

**Restated for adoption of FIN 46.*

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

	Millions of Dollars			
	Three Months Ended September 30		Nine Months Ended September 30	
	2004	2003	**2004**	2003*
Exploration and Production (E&P)	**$ 1,420**	967	**4,031**	3,311
Midstream	**38**	31	**135**	87
Refining and Marketing (R&M)	**708**	485	**1,990**	1,070
Chemicals	**81**	7	**166**	(4)
Emerging Businesses	**(27)**	(18)	**(78)**	(75)
Corporate and Other	**(214)**	(166)	**(547)**	(675)
Net income	**$ 2,006**	1,306	**5,697**	3,714

**Restated for adoption of FIN 46.*

Net income was $2,006 million in the third quarter of 2004, compared with $1,306 million in the third quarter of 2003. In the September 2004 year-to-date period, net income was $5,697 million, compared with $3,714 million in the corresponding period of 2003. The improved results in both 2004 periods primarily were the result of improved refining and chemicals margins and higher crude oil prices.

Income Statement Analysis

Sales and other operating revenues increased 32 percent and 22 percent in the third quarter and first nine months of 2004, respectively, while purchased crude oil and products increased 37 percent and 24 percent in the same periods. 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 its 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 109 percent in the third quarter of 2004 and 151 percent in the nine-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 nine-month period;
- Our chemicals joint venture, Chevron Phillips Chemical Company LLC, due to higher volumes and margins;
- 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 crude oil light-heavy differentials.

Other income decreased 93 percent in the third quarter of 2004, and 44 percent in the nine-month period, primarily due to lower net gains on asset dispositions in the 2004 periods.

Exploration expenses increased 55 percent in the third quarter of 2004 and 31 percent in the nine-month period. The increases in both periods primarily were due to higher dry hole charges and leasehold impairments. Dry hole charges in the first nine months of 2004 included exploratory activity in Alaska, the Gulf of Mexico, Venezuela, Canada, Vietnam, and Azerbaijan. Significant leasehold impairments were recorded on leases in Brazil, Nigeria, and the United Kingdom.

Interest and debt expense declined 47 percent in the third quarter of 2004 and 37 percent in the nine-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 third quarter and first nine months of 2004 were 45 percent and 44 percent, respectively, compared with 46 percent for the corresponding periods in 2003. There were not any material changes in the effective tax rate between the third quarter of 2004 and the third quarter of 2003. The reduction in the effective tax rate for the first nine months of 2004, versus the same period in 2003, mainly was due to the impact of a higher proportion of income in lower tax rate jurisdictions.

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 Financial Accounting Standards Board Interpretation No. 46, “Consolidation of Variable Interest Entities” (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 nine-month 2003 period for the cumulative effect of the two accounting changes.

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 September 30		Nine Months Ended September 30	
	2004	2003	**2004**	2003
	Millions of Dollars			
Net Income				
Alaska	$ **451**	302	**1,251**	1,112
Lower 48	**250**	244	**756**	771
United States	**701**	546	**2,007**	1,883
International	**719**	421	**2,024**	1,428
	$ **1,420**	967	**4,031**	3,311
	Dollars Per Unit			
Average Sales Prices				
Crude oil (per barrel)				
United States	$ **40.33**	28.26	**36.23**	28.99
International	**40.47**	28.05	**35.64**	28.22
Total consolidated	**40.41**	28.15	**35.90**	28.57
Equity affiliates	**25.86**	19.90	**22.93**	18.84
Worldwide	**38.77**	27.00	**34.34**	27.55
Natural gas—lease (per thousand cubic feet)*				
United States	**5.19**	4.45	**5.14**	4.83
International	**3.98**	3.42	**3.97**	3.63
Total consolidated	**4.48**	3.84	**4.44**	4.11
Equity affiliates	**.31**	4.12	**2.59**	4.61
Worldwide	**4.48**	3.84	**4.44**	4.12

**Certain 2003 amounts revised.*

	Millions of Dollars			
Worldwide Exploration Expenses				
General administrative; geological and geophysical; and lease rentals	$ **55**	57	**169**	221
Leasehold impairment	**68**	36	**151**	80
Dry holes	**82**	39	**191**	89
	$ **205**	132	**511**	390

	Three Months Ended September 30		Nine Months Ended September 30	
	2004	2003	**2004**	2003
	Thousands of Barrels Daily			
Operating Statistics				
Crude oil produced				
Alaska	**253**	314	**293**	327
Lower 48	**50**	51	**51**	56
United States	**303**	365	**344**	383
European North Sea	**248**	274	**269**	294
Asia Pacific	**103**	55	**92**	60
Canada	**24**	29	**25**	31
Other areas	**55**	70	**60**	73
Total consolidated	**733**	793	**790**	841
Equity affiliates	**111**	120	**109**	97
	844	913	**899**	938
Natural gas liquids produced				
Alaska	**19**	19	**23**	22
Lower 48	**26**	25	**25**	24
United States	**45**	44	**48**	46
European North Sea	**16**	9	**14**	10
Canada	**10**	9	**11**	10
Other areas	**16**	—	**8**	2
	87	62	**81**	68
	Millions of Cubic Feet Daily			
Natural gas produced*				
Alaska	**164**	180	**166**	177
Lower 48	**1,220**	1,271	**1,226**	1,306
United States	**1,384**	1,451	**1,392**	1,483
European North Sea	**994**	1,069	**1,106**	1,200
Asia Pacific	**298**	336	**295**	309
Canada	**425**	448	**430**	436
Other areas	**78**	69	**75**	59
Total consolidated	**3,179**	3,373	**3,298**	3,487
Equity affiliates	**4**	11	**5**	11
	3,183	3,384	**3,303**	3,498

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

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

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 September 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 47 percent in the third quarter of 2004, and 22 percent in the nine-month period. In both periods, the increases primarily were due to higher crude oil prices and, to a lesser extent, higher natural gas and natural gas liquids prices. Increased sales prices were partially offset by lower crude oil and natural gas production, as well as higher exploration expenses and lower net gains on asset dispositions. The 2003 nine-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 28 percent in the third quarter of 2004, and 7 percent in the nine-month period. The increases in both periods were 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 crude oil and natural gas production volumes and lower net gains on asset dispositions. The nine-month period of 2003 included a net benefit of $142 million 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 579,000 barrels per day in the third quarter of 2004, down 11 percent from 651,000 BOE per day in the third quarter of 2003. The decreased production primarily was the result of 2003 asset dispositions, field production declines, and planned maintenance.

International E&P

Net income from our international E&P operations increased 71 percent in the third quarter of 2004, and 42 percent in the nine-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 and higher natural gas liquids volumes. Higher prices were partially offset by increased exploration expenses and lower net gains on asset dispositions.

International E&P production on a barrel-of-oil-equivalent (BOE) basis averaged 883,000 barrels per day in the third quarter of 2004, down slightly from 888,000 BOE per day in the third 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 the impact of asset dispositions, field production declines, and planned maintenance.

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Midstream

		Three Months Ended September 30		Nine Months Ended September 30	
		2004	2003	**2004**	2003
		Millions of Dollars			
Net income*	$	**38**	31	**135**	87
**Includes DEFS-related net income:*	*$*	***26***	*18*	***92***	*54*
		Dollars Per Barrel			
Average Sales Prices					
U.S. natural gas liquids*					
Consolidated	$	**31.03**	20.94	**27.71**	22.51
Equity		**30.27**	20.67	**26.90**	21.91

* *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*	**194**	215	**195**	213
Natural gas liquids fractionated**	**207**	232	**205**	222

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

The Midstream segment purchases raw natural gas from producers and gathers natural gas through an extensive network of pipeline gathering systems. The natural gas is then processed to extract natural gas liquids from the raw gas stream. The remaining “residue” gas is marketed to electrical utilities, industrial users, and gas marketing companies. Most of the natural gas liquids are fractionated — separated into individual components like ethane, butane and propane — and marketed as chemical feedstock, fuel, or blendstock. The Midstream segment consists of our 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 23 percent in the third quarter of 2004, and 55 percent in the nine-month period. The improvements were primarily attributable to improved results from DEFS, which had:

- Higher gross margins, primarily reflecting higher natural gas liquids prices; and
- In the nine-month period results, a $23 million (gross) charge in the first nine months of 2003 for the cumulative effect of accounting changes, mainly related to the adoption of SFAS No. 143; partially offset by:
- Investment impairments and write-downs of assets held for sale in the third quarter of 2004.

Our Midstream operations outside of DEFS had slightly lower earnings in the third quarter of 2004, while results improved 30 percent in the nine-month period. In the quarter, higher natural gas liquids sales prices were more than offset by the effect of asset dispositions in the second quarter of 2004 and inventory impacts. In the nine-month period, the impact of higher natural gas liquids prices exceeded the effect of asset dispositions in the second quarter of 2004 and inventory impacts.

Included in the Midstream segment's net income was a benefit of $9 million in the third quarter of 2004, the same as the third 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 nine-month periods was $27 million.

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R&M

	Three Months Ended September 30		Nine Months Ended September 30	
	2004	2003	**2004**	2003
	Millions of Dollars			
Net Income				
United States	$ **505**	416	**1,642**	814
International	**203**	69	**348**	256
	$ **708**	485	**1,990**	1,070

	Three Months Ended September 30		Nine Months Ended September 30	
	2004	2003	**2004**	2003
	Dollars Per Gallon			
U.S. Average Sales Prices*				
Automotive gasoline				
Wholesale	$ **1.37**	1.09	**1.31**	1.07
Retail	**1.51**	1.42	**1.48**	1.38
Distillates—wholesale	**1.30**	.88	**1.18**	.93

**Excludes excise taxes.*

	Three Months Ended September 30		Nine Months Ended September 30	
	2004	2003	**2004**	2003
	Thousands of Barrels Daily			
Operating Statistics				
Refining operations*				
United States				
Rated crude oil capacity	**2,160**	2,168	**2,165**	2,168
Crude oil runs	**2,011**	2,083	**2,078**	2,073
Capacity utilization (percent)	**93%**	96	**96**	96
Refinery production	**2,198**	2,322	**2,248**	2,311
International				
Rated crude oil capacity	**428**	442	**441**	442
Crude oil runs**	**425**	417	**381**	430
Capacity utilization (percent)**	**99%**	94	**86**	97
Refinery production	**439**	413	**389**	419
Worldwide				
Rated crude oil capacity	**2,588**	2,610	**2,606**	2,610
Crude oil runs**	**2,436**	2,500	**2,459**	2,503
Capacity utilization (percent)**	**94%**	96	**94**	96
Refinery production	**2,637**	2,735	**2,637**	2,730

**Includes ConocoPhillips' share of equity affiliates.*
***2003 amounts reclassified to conform to 2004 presentation.*

Petroleum products outside sales				
United States				
Automotive gasoline	**1,366**	1,398	**1,337**	1,370
Distillates	**544**	580	**551**	590
Aviation fuels	**200**	197	**190**	176
Other products	**553**	497	**548**	499
	2,663	2,672	**2,626**	2,635
International	**472**	441	**470**	439
	3,135	3,113	**3,096**	3,074

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 46 percent in the third quarter of 2004, and 86 percent in the first nine months. The increase in both periods of 2004 primarily was due to higher refining margins. This was partially offset by lower wholesale and retail marketing margins, higher maintenance and utility costs, and increased contingency accruals. In the nine-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 21 percent in the third quarter of 2004, and 102 percent in the first nine months. The increase in the third quarter and nine-month period of 2004 primarily was due to higher refining margins, partially offset by lower wholesale and retail marketing margins, higher maintenance and utility costs, and increased contingency accruals. In the nine-month period comparison, the 2003 period included a $125 million net charge for the cumulative effect of accounting change (FIN 46).

Our U.S. refining capacity utilization rate was 93 percent in the third quarter of 2004, compared with 96 percent in the third quarter of 2003. The lower capacity utilization was due to increased maintenance downtime.

International R&M

Net income from the international R&M operations increased 194 percent in the third quarter of 2004, and 36 percent in the nine-month period. The improvement in the third quarter of 2004 was attributable to higher refining margins. In the nine-month period comparison, higher refining margins were partially offset by lower marketing margins, lower refinery production volumes, higher maintenance turnaround costs and negative foreign currency impacts.

Our international crude oil refining capacity utilization rate was 99 percent in the third quarter of 2004, compared with 94 percent in the corresponding period of 2003. Beginning in the third quarter of 2004, we changed our crude oil capacity utilization statistic at the Humber refinery to make it consistent with our other refineries. Prior periods have been reclassified to reflect this change.

Chemicals

	Millions of Dollars			
	Three Months Ended September 30		Nine Months Ended September 30	
	2004	2003	**2004**	2003
Net income (loss)	$ **81**	7	**166**	(4)

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 $74 million in the third quarter of 2004, compared with the third quarter of 2003. In the nine-month period, the Chemicals segment had net income of $166 million in 2004, compared with a net loss of $4 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. Results from CPChem's consolidated operations also improved from higher ethylene and benzene margins, as well as increased ethylene and polyethylene sales volumes.

Emerging Businesses

	Millions of Dollars			
	Three Months Ended September 30		Nine Months Ended September 30	
	2004	2003	**2004**	2003
Net Loss				
Technology solutions	$ **(3)**	(5)	**(11)**	(16)
Gas-to-liquids	**(9)**	(7)	**(25)**	(40)
Power	**(8)**	(3)	**(28)**	(3)
Other	**(7)**	(3)	**(14)**	(16)
	$ **(27)**	(18)	**(78)**	(75)

The Emerging Businesses segment includes the development of new businesses outside our traditional operations. Emerging Businesses incurred a net loss of $27 million in the third quarter of 2004, compared with a net loss of $18 million in the third quarter of 2003. In the nine-month period, Emerging Businesses incurred a net loss of $78 million in 2004, compared with a net loss of $75 million in 2003. Both 2004 periods reflect increased costs associated with the Immingham power plant project in the United Kingdom, which was 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. This project completed the initial commissioning phase and began commercial operations in October 2004. Partially offsetting the higher Immingham costs in the nine-month period were lower research and development costs, compared with the 2003 period, which included the costs of a demonstration gas-to-liquids plant then under construction. Construction of the gas-to-liquids plant was substantially completed during the second quarter of 2003.

Corporate and Other

	Millions of Dollars			
	Three Months Ended September 30		Nine Months Ended September 30	
	2004	2003	**2004**	2003
Net Income (Loss)				
Net interest	**$ (120)**	(134)	**(343)**	(469)
Corporate general and administrative expenses	**(51)**	(33)	**(160)**	(106)
Discontinued operations	**(5)**	57	**70**	201
Merger-related costs	**—**	(41)	**(14)**	(183)
Cumulative effect of accounting changes	**—**	—	**—**	(112)
Other	**(38)**	(15)	**(100)**	(6)
	$ (214)	(166)	**(547)**	(675)

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 10 percent in the third quarter of 2004, and 27 percent in the first nine months. The decrease in both periods primarily was due to lower average debt levels and an increased amount of interest being capitalized in the 2004 periods, partially offset by higher charges for premiums paid on the early retirement of debt.

After-tax corporate general and administrative expenses increased 55 percent in the third quarter of 2004 and 51 percent in the nine-month period. The increase in both periods reflects higher compensation costs, which includes increased stock-based compensation due to an increase in both the number of units issued and our higher stock prices in the 2004 periods.

Discontinued operations had a net loss of $5 million in the third quarter of 2004, compared with net income of $57 million in the third quarter of 2003. For the nine-month period, discontinued operations net income declined 65 percent. Both decreases reflect asset dispositions completed during 2003 and 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 the third quarter of 2004, mainly due to higher minority interest and tax expense, partially offset by higher foreign currency gains. Results were lower in the nine-month period of 2004 because of higher minority interest, environmental costs and tax expense, as well as the inclusion in the 2003 period of gains related to insurance demutualization benefits.

CAPITAL RESOURCES AND LIQUIDITY

Financial Indicators

		Millions of Dollars	
		At September 30 2004	At December 31 2003
Current ratio		**1.1**	.8
Total debt repayment obligations due within one year	$	**1,079**	1,440
Total debt	$	**15,486**	17,780
Minority interests	$	**1,036**	842
Common stockholders' equity	$	**39,767**	34,366
Percent of total debt to capital*		**28%**	34
Percent of floating-rate debt to total debt		**21%**	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 nine months of 2004, we raised approximately $1.4 billion in funds from the sale of assets. During the first nine 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 nine months of 2004 were $886 million. During the first nine months of 2004, cash and cash equivalents increased $2,773 million to $3,263 million. Our cash balance at September 30, 2004, was reduced by $1,988 million in early October when we acquired a 7.6 percent interest in LUKOIL. See the Outlook section for additional information.

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 nine 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 (2001, 2002 and 2003). 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, excluding any impact from a potential royalty rate change in Venezuela (see the Outlook section for additional information on this item), 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. The net addition of proved undeveloped reserves accounted for 76 percent, 34 percent and

23 percent of our total net additions in 2003, 2002 and 2001, respectively. For additional information related to the development of proved undeveloped reserves, see the discussion under the E&P section of Capital Spending. For additional information about our total proved reserves, including the extent to which reserve replacement was attributable to revisions in estimates; property acquisitions; exploration activities; and improved recovery, see the supplemental Oil and Gas Operations disclosures about Proved Reserves Worldwide in our 2003 Form 10-K. Going forward, we expect our average reserve replacement to exceed 100 percent of our production over the next three years. However, these anticipated production and reserve replacement 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; governmental and 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 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 of Financial Condition and Results of Operations 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 nine months of 2004, cash of $8,762 million was provided by operating activities, an increase of $1,438 million, compared with the same period in 2003. This increase in cash provided by operating activities was primarily due to an increase in income from continuing operations, partially offset by an increase in working capital. The working capital increase primarily was driven by higher accounts receivable and a higher retained interest in receivables sold to a Qualifying Special Purpose Entity (QSPE), partly offset by higher accounts payable. Contributing to the increase in accounts receivable and accounts payable were higher sales and purchase prices, respectively. For additional information on income from continuing operations, see the Results of Operations section. For additional information on receivables sold to a QSPE, see Receivables Monetization in the Off-Balance Sheet Arrangements section.

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 nine months of 2004, proceeds from asset sales were $1.4 billion, bringing total proceeds to approximately $4.8 billion since the program began. While we will continue to have modest asset disposition activity, this asset disposition program was essentially completed at the end of the second quarter of 2004.

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 our commercial paper program, which we increased from $4 billion to $5 billion in October 2004. A portion of our commercial paper program may be denominated in other currencies (limited to euro 3 billion equivalent). Commercial paper maturities are generally kept within 90 days. At September 30, 2004, we had $1 billion of commercial paper outstanding, compared with $709 million of commercial paper outstanding at December 31, 2003.

At September 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 commercial paper program. There were no outstanding borrowings under any of these facilities at September 30, 2004. One of our Norwegian subsidiaries had two $300 million revolving credit facilities that expired in June 2004, which were not renewed.

On October 12, 2004, we replaced the four bank credit facilities noted above with two facilities totaling $5 billion. The facilities include a $2.5 billion four-year facility expiring in October 2008 and a $2.5 billion five-year facility expiring in October 2009. Both facilities are available for use as direct bank borrowings or as support for our $5 billion commercial paper program. In addition, the five-year facility may be used to support issuances of letters of credit totaling up to $750 million. The facilities are syndicated among 40 financial institutions and do not contain any material adverse change provisions or any covenants requiring maintenance of specified financial ratios or ratings. The credit agreements do contain a cross-default provision relating to our, or any of our consolidated subsidiaries', failure to pay principal or interest on other debt obligations of $200 million or more.

Minority Interests

At September 30, 2004, we had outstanding $1,036 million of equity that was held by minority interest owners, including a minority interest of $504 million in Ashford Energy Capital S.A. The remaining minority interest amounts related to controlled operating joint ventures with minority interest owners. The largest of these, $473 million, was related to the Bayu-Undan liquefied natural gas project in the Timor Sea. During the third quarter of 2004, a $141 million net minority interest in Conoco Corporate Holdings L.P. was retired.

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 September 30, 2004, we had no receivables outstanding under similar arrangements.

Off-Balance Sheet Arrangements

Receivables Monetization

At September 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 September 30, 2004, and December 31, 2003, the QSPE had issued beneficial interests to the bank-sponsored entities of $600 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 $2.4 billion at September 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.

Capital Requirements

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

Our balance sheet debt at September 30, 2004, was $15.5 billion. This reflects debt reductions of approximately $2.3 billion during the first nine months of the year. The reduction primarily resulted from repayment in April of the $1,350 million aggregate principal amount of our 5.90% Notes due 2004 at maturity, and the redemption in August 2004 of the $1,150 million aggregate principal amount of our 8.5% Notes due 2005, partly offset by an increase of $291 million in our outstanding commercial paper balance. The 8.5% Notes were redeemed at a premium of $58 million plus accrued interest. Going forward, we have no significant mandatory debt retirements until payment of the $1,250 million aggregate principal amount of our 5.45% Notes due in 2006, at maturity.

In September 2004, we announced a new quarterly dividend rate of 50 cents per share for our common stock, an increase of 16 percent. The dividend is payable on December 1, 2004, to stockholders of record at the close of business November 1, 2004.

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Capital Spending

Capital Expenditures and Investments

		Millions of Dollars	
		Nine Months Ended September 30	
		2004	2003
E&P			
United States—Alaska	$	**472**	426
United States—Lower 48		**474**	634
International		**2,751**	2,228
		3,697	3,288
Midstream		**6**	6
R&M			
United States		**580**	546
International		**190**	204
		770	750
Chemicals		**—**	—
Emerging Businesses		**74**	224
Corporate and Other*		**112**	117
	$	**4,659**	4,385
United States	$	**1,646**	1,747
International		**3,013**	2,638
	$	**4,659**	4,385
Discontinued operations	$	**2**	47

**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 have increased oil production capacity at the Alpine field with the completion of Alpine Capacity Expansion (ACX)-Phase 1 and a significant portion of Phase 2. We expect to complete the final component of Phase 2 in mid-2005. The capacity expansion projects have increased 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 six North Slope exploration wells, which resulted in three successful appraisal wells in the National Petroleum Reserve-Alaska (NPR-A) and a satellite field near Alpine. The other three wells were expensed as dry holes. 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 and Hawaii. In early October 2004, the Polar Adventure, the fourth of five vessels, began service. We expect to add the fifth and final Endeavour Class tanker to our fleet in 2005.

During the third quarter, we announced plans to participate in the largest-ever heavy oil development program in Alaska. Our net cost in the development program is estimated to be approximately $275 million.

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 the second half of 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 be fully operational by mid-2006.

Also in Canada, development expenditures have started for the Surmont heavy-oil project. In 2003, we designated 223 million barrels as 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, however, because the average production and steam-injected well pair is expected to produce approximately 1 million net barrels, 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 nine months of 2004, our capital expenditures associated with Surmont were approximately $17 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. Mechanical completion of the upgrader was achieved in September 2004. In October, we began charging the upgrader with extra-heavy crude oil with our focus toward stabilizing the upgrader and producing on-specification synthetic crude oil for export at the planned capacity of the plant in the fourth quarter of 2004. Progress toward that goal was made on October 20, 2004, when the project shipped its first commercial cargo of approximately 500,000 gross barrels. Once the upgrader is producing at the planned capacity, our net production from the Hamaca field is expected to increase to approximately 71,000 barrels per day, excluding the impact of any royalty rate change that may occur (see the Outlook section for additional information). Throughout the third quarter, the project produced blended bitumen at an average of 32,000 net barrels per day.

In Brazil, after further evaluation, we wrote-off our remaining leasehold investment in Block BM-PAMA-3 in April 2004. Government approval was received from the Brazilian government in August 2004. We plan to cease all operations in Brazil and exit the country in the fourth 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.

During the third quarter, we announced that we had received approval from U.K. authorities to develop the Saturn Unit Area in the U.K. Southern North Sea. First production is expected in the fourth quarter of 2005.

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. Discussions continue with the Republic of Kazakhstan authorities over pre-emption rights related to the sale by BG International of their share in the North Caspian License. In the South Caspian, drilling was completed on the Zafar-Mashal #1 exploration well in Azerbaijan waters. The well was declared non-commercial and was written off 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, the Bayu-Undan gas recycle project began first liquids production in February 2004. Peak capacity of 62,000 net barrels per day of condensate and gas liquids was achieved in early September 2004. An annual average rate of 25,700 net barrels per day of combined condensate and natural gas liquids is expected for 2004. All Phase I development drilling is expected to be completed by March 2005.

Also during the first nine 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 September, the LNG project was approximately 58 percent complete and 79 of the 312 miles of pipeline had been laid, with the overall pipeline project being approximately 63 percent complete. 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 continued the construction of the Belanak FPSO and the development of the Belanak field in the South Natuna Sea Block B. The FPSO began sailing from Batam in October to its permanent location in the South Natuna Sea, where commissioning and hook-up will continue offshore. Commercial production from Belanak is targeted to commence in late 2004. Also, in Block B we began development of the Kerisi and Hiu fields, with contract awards under way, and we began the preliminary engineering phase of the North Belut field development. In South Sumatra, immediately following the execution of the West Java gas sales agreement with PT Perusahaan Gas Negara (Persero) Tbk. in August, we awarded the engineering procurement construction and installation contract and began the development of the Suban Phase II project, which is an expansion of the existing Suban gas plant. Also in South Sumatra, we completed the construction of the South Jambi gas project in the South Jambi B Block, with first production occurring in June 2004.

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) as follows:

- 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 (2004/2005); and
- Magnolia field in the Gulf of Mexico (2004/2005).

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, including investing in a new diesel hydrotreater at the Rodeo facility of our San Francisco-area refinery. The new diesel hydrotreater is expected 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 nine months of 2004 to complete our Immingham combined heat and power cogeneration plant near our Humber refinery in the United Kingdom. The plant began commercial operations in early October 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 June 2006. In April 2003, the EPA proposed a rule regarding emissions from non-road diesel engines and limiting non-road diesel fuel sulfur content. The non-road rule, as promulgated in June 2004, significantly reduces non-road diesel fuel sulfur content limits as early as 2007. We are evaluating and developing capital strategies for future integrated compliance for our entire diesel fuel pool.

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 ratify, support or sponsor either it or other climate change related emissions reduction programs. 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. Because considerable uncertainty exists with respect to the regulations that would ultimately govern implementation of the Kyoto Protocol, it currently is not possible to accurately estimate our future compliance costs under the Kyoto Protocol, but they 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 September 30, 2004, we had resolved five of these sites, reclassified one site as unresolved, and had received eight new notices of potential liability, leaving 65 unresolved sites where we have been notified of potential liability.

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

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 September 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 September 30, 2004, our balance sheet included a total environmental accrual of $1,148 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 May 2003, the Financial Accounting Standards Board (FASB) issued Statement of Financial Accounting Standards (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 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 revised Statement does not change the measurement or recognition of employee benefit plans. We adopted the provisions of the Statement 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 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 consensus on Issue 03-6, "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 in this report.

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. In September 2004, the FASB issued Staff Position No. 142-2, which confirmed that the scope exception in paragraph 8(b) of SFAS No. 142 extends to the disclosure provision for oil-and-gas producing entities. The effective date for this FASB Staff Position is October 1, 2004. See Note 7—Properties, Plants and Equipment, in the Notes to Consolidated Financial Statements, for more information.

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.

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, 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 exploration and production (E&P) operations. There are several authoritative guidelines regarding the engineering criteria that must be met before estimated reserves can be designated as “proved.” Our reservoir engineering 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 properties, plants 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 the 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 third 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. Our largest asset removal obligations 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 must 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.

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 must 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 must be applied in determining the fair values of individual assets and liabilities for purposes of the hypothetical purchase price allocation. Again, management must use all available information to make these fair value determinations 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 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, excluding any potential royalty rate change in Venezuela, we expect our worldwide production for the fourth quarter of 2004 to be above our third quarter level, primarily because of a lower level of scheduled maintenance and normal seasonal increases in the United Kingdom, Norway and Alaska, as well as startup of the Hamaca upgrader in Venezuela.

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

In the second quarter, Norwegian authorities ordered us to modify our facilities at two Ekofisk Area installations — Ekofisk and Eldfisk — and had initially given us until October 1, 2004, (now deferred by Norwegian authorities to December 31, 2004) to submit a plan for implementing measures to ensure workers are not disturbed by noise 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 net to comply with their order for temporary and permanent measures at Eldfisk and temporary measures at Ekofisk. We are appealing this order.

Also, in Norway, we and our co-venturers received approval from Norwegian authorities in October 2004 for the Alvheim North Sea development. The development will include a floating production storage and offloading vessel and subsea installations. Production from the field is expected to commence in 2007. We have a 20 percent interest in the project.

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. Due to the significance of the overall investment in these long-term projects, the natural gas sales prices (to a third-party LNG facility) or transfer prices (to a company-owned LNG facility) in the areas of excess supply are expected to remain well below sales prices for natural gas that is produced closer to areas of high demand and which can be transferred to existing natural gas pipeline networks, such as in the U.S. Lower 48.

In early July 2004, we announced the finalization of our transaction with Freeport LNG Development, L.P. (Freeport LNG) to participate in a proposed LNG receiving terminal in Quintana, Texas. Freeport LNG received conditional approval in June 2004 from the Federal Energy Regulatory Commission (FERC) to construct and operate the facility. Receipt of all other necessary federal, state and local approvals is expected in the fourth quarter of this year. Construction is scheduled to begin in the fourth quarter of 2004, with commercial startup planned for the fourth quarter of 2007. We do not have any limited partner ownership interest in the facility, but we do have a 50 percent interest in the general partnership managing the venture. In addition, we have contractual rights to two-thirds of the LNG regasification capacity in the facility, or 1 billion cubic feet per day. We have entered into a credit agreement with Freeport LNG, whereby we will provide financing support of approximately $600 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.

The Mackenzie gas project involves natural gas production facilities for three anchor fields, including the Parsons Lake field operated by us; compression and gathering pipelines in the Mackenzie Delta area; and a pipeline system in the Mackenzie River Valley. In September 2004, the National Energy Board in Canada confirmed the Commercial Discovery Declaration (CDD) for the Parsons Lake field. The CDD meets our development planning expectations, which is an important milestone in the regulatory approval process toward obtaining a production license. The main regulatory applications were filed in October 2004, triggering the start of the formal environmental and regulatory review process. This filing sets the stage for regulatory hearings in 2005, leading toward a regulatory decision in 2006. First gas production is currently targeted to commence in late 2009.

In August 2004, we announced the signing of a gas sales agreement with PT Perusahaan Gas Negara (Persero) Tbk., the Indonesian state-owned gas transportation company, to supply a base load of natural gas for delivery to the industrial market in West Java and Jakarta. The agreement calls for us to supply 1.24 trillion net cubic feet of gas over a 17-year period commencing in the first quarter of 2007, at a rate of 92 million net cubic feet per day. The gas will come from our operated Corridor Block production sharing contract in South Sumatra. Gas deliveries are expected to plateau at 216 million net cubic feet per day in 2012 and continue at that level until the contract termination in 2023.

On September 29, 2004, we made a joint announcement with LUKOIL, an international integrated oil and gas company headquartered in Russia, of an agreement to form a broad-based strategic alliance, whereby we would become a strategic equity investor in LUKOIL. Together, we also announced our intention to form a joint venture between the two companies to develop resources in the northern part of Russia’s Timan-Pechora oil and gas province and the intention of the two companies to jointly seek the right to develop the West Qurna oil field in Iraq.

In the announcement, we disclosed that we were the successful bidder in an auction of 7.6 percent of LUKOIL’s authorized and issued ordinary shares held by the Russian government for a price of $1,988 million, or $30.76 per share. The transaction closed on October 7, 2004. We expect, however, to increase our ownership in LUKOIL to approximately 10 percent by the end of 2004 if market conditions permit. Under the Shareholder Agreement between the two companies, we will have proportional membership on the LUKOIL Board of Directors (Board) and LUKOIL will propose for shareholder approval amendments to its corporate charter that will require unanimous Board consent for certain key decisions. We expect that one of our nominees will be elected to the LUKOIL Board in early 2005. In addition, the Shareholder Agreement allows us to increase our ownership interest in LUKOIL to 20 percent and limits our ability to sell our LUKOIL shares for a period of four years except in certain circumstances.

Under the terms of the joint-venture arrangements, we will pay an acquisition price to LUKOIL of approximately $370 million for a 30 percent economic interest in the joint venture to develop oil and gas resources in the northern part of Russia’s Timan-Pechora province, together with an additional payment for LUKOIL’s 30 percent share of working capital and its 30 percent share of capital investments in the joint-venture fields from January 1, 2004. Under the joint-venture arrangements, we will have a 50 percent voting interest. The exact amount of the acquisition price will be established at closing, which is anticipated in the first quarter of 2005.

In addition, we, along with LUKOIL, will cooperate with the Iraqi government to confirm the validity of LUKOIL's rights under its production sharing agreement (PSA) relating to the West Qurna field in Iraq. Subject to confirmation and the consents of governmental authorities and the parties to the contract, we expect to enter into further agreements regarding the assignment by LUKOIL to us of a 17.5 percent interest in the PSA.

In October, the President of Venezuela made a public statement that the reduction in the royalty rate to 1 percent from 16.67 percent for a period of nine years, or until revenues exceed three times the initial investment, would no longer apply to extra-heavy crude oil producing and processing projects. We are evaluating the potential impact of this matter on our Hamaca and Petrozuata projects, but currently estimate that if the revised royalty rate were to be in effect for all of next year, our worldwide production for 2005 would be reduced approximately 20,000 barrels-of-oil-equivalent per day.

Elsewhere, we are participating in discussions with our co-venturers and Libyan authorities about lease concession terms in connection with our possible re-entry into that country.

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 changes in costs or technical requirements for constructing, modifying or operating facilities for exploration and production projects, manufacturing or refining;
- Unexpected technological or commercial difficulties in manufacturing or refining our products, including synthetic crude oil and chemicals products;

- Lack of, or disruptions in, adequate and reliable transportation for our crude oil, natural gas, natural gas liquids, LNG and refined products;
- Inability to timely obtain or maintain permits, including those necessary for construction of LNG terminals or regasification facilities, comply with government regulations, or make capital expenditures required to maintain compliance;
- Failure to complete definitive agreements and feasibility studies for, and to timely complete construction of, announced and future LNG projects and related facilities;
- Potential disruption or interruption of our operations due to accidents, extraordinary weather events, civil unrest, political events or terrorism;
- International monetary conditions and exchange controls;
- 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, regulations or royalty rules applicable to our business;
- Inability to obtain economical financing for exploration and development projects, construction or modification of facilities and general corporate purposes; and
- Inability to increase ownership in LUKOIL to approximately 10 percent by the end of 2004 through open market purchases.

Item 3. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

Information about market risks for the nine months ended September 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 September 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 September 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, distillates and heavy intermediate product business. In a future phase scheduled for 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.

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PART II. OTHER INFORMATION

Item 1. LEGAL PROCEEDINGS

With the exception of the two matters described below, there have been no material developments with respect to the legal proceedings previously reported in our first quarter or second quarter 2004 Form 10-Q, or our 2003 Annual Report on Form 10-K.

On September 17, 2003, U.S. EPA Region 10 notified ConocoPhillips of its intent to assess civil penalties for alleged National Pollution Discharge Elimination System (NPDES) permit violations at our Tyonek offshore platform located near Cook Inlet, Alaska. The alleged violations arise from our July 2003 NPDES self-disclosure report to EPA Region 10. On February 10, 2004, EPA Region 10 issued to us a proposed Complaint for Civil Penalties and a proposed Consent Decree for the alleged permit violations. In August 2004, we agreed to resolve this matter by paying a civil penalty in the amount of $485,000.

In August 2004 Polar Tankers, Inc., a subsidiary of ConocoPhillips Company, self-reported to the U.S. Coast Guard that a company employee had disclosed to management potential environmental violations onboard the vessel Polar Alaska. The potential violations relate to allegations that certain actions may have resulted in one or more wastewater streams being discharged potentially having concentrations of oil exceeding an applicable regulatory limit of 15 parts per million. On September 1, 2004, the United States Attorney’s office in Anchorage issued a subpoena for records to ConocoPhillips Company and Polar Tankers, Inc. relating to the company’s report of potential violations. The company is fully cooperating with the governmental authorities.

Item 2. UNREGISTERED SALES OF EQUITY SECURITIES AND USE OF PROCEEDS

Issuer Purchases of Equity Securities

Period	Total Number of Shares Purchased*	Average Price** Paid per Share	Total Number of Shares Purchased as Part of Publicly Announced Plans or Programs***	Maximum Number of Shares that May Yet Be Purchased Under the Plans or Programs
July 1-31, 2004	6,403	$ 77.86	—	—
August 1-31, 2004	326	73.81	—	—
September 1-30, 2004	3,018	79.95	—	—
Total	9,747	$ 78.38	—	—

**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.*

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Item 6. EXHIBITS

Exhibits

10.1	ConocoPhillips Key Employee Change in Control Severance Plan, effective October 1, 2004.
10.2	ConocoPhillips Executive Severance Plan, effective October 1, 2004.
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.

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)

November 4, 2004

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EXHIBIT INDEX

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Exhibit 10.1

CONOCOPHILLIPS
KEY EMPLOYEE CHANGE IN CONTROL SEVERANCE PLAN

(Effective October 1, 2004)

Effective October 1, 2004, the Company adopts this the ConocoPhillips Key Employee Change in Control Severance Plan (the "Plan") for the benefit of certain employees of the Company and its subsidiaries.

All capitalized terms used herein are defined in Section 1 hereof. This Plan is intended to be a plan maintained primarily for the purpose of providing deferred compensation for a select group of management or highly compensated employees, within the meaning of Title I of the Employee Retirement Income Security Act of 1974, as amended and shall be interpreted in a manner consistent with such intention.

SECTION 1. <u>DEFINITIONS</u>. As hereinafter used:

1.1 "Affiliate" has the meaning ascribed to such term in Rule 12b-2 of the General Rules and Regulations under the Exchange Act, as in effect on the Effective Date.

1.2 "Associate" means, with reference to any Person, (a) any corporation, firm, partnership, association, unincorporated organization, or other entity (other than the Company or a subsidiary of the Company) of which such Person is an officer or general partner (or officer or general partner of a general partner) or is, directly or indirectly, the Beneficial Owner of 10% or more of any class of equity securities, (b) any trust or other estate in which such Person has a substantial beneficial interest or as to which such Person serves as trustee or in a similar fiduciary capacity, and (c) any relative or spouse of such Person, or any relative of such spouse, who has the same home as such Person.

1.3 "Beneficial Owner" means, with reference to any securities, any Person if:

(a) such Person or any of such Person's Affiliates and Associates, directly or indirectly, is the "beneficial owner" of (as determined pursuant to Rule 13d-3 of the General Rules and Regulations under the Exchange Act, as in effect on the Effective Date) such securities or otherwise has the right to vote or dispose of such securities, including pursuant to any agreement, arrangement, or understanding (whether or not in writing); provided, however, that a Person shall not be deemed the "Beneficial Owner" of, or to "beneficially own," any security under this subsection (a) as a result of an agreement, arrangement, or understanding to vote such security if such agreement, arrangement, or understanding: (i) arises solely from a revocable proxy or consent given in response to a public (*i.e.*, not including a solicitation exempted by Rule 14a-2(b)(2) of the General Rules and Regulations under the Exchange Act) proxy or consent solicitation made pursuant to, and in accordance with, the applicable provisions of the General Rules and Regulations under the Exchange Act, and (ii) is not then reportable by such Person on Schedule 13D under the Exchange Act (or any comparable or successor report);

(b) such Person or any of such Person's Affiliates and Associates, directly or indirectly, has the right or obligation to acquire such securities (whether such right or obligation is exercisable or effective immediately or only after the passage of time or the occurrence of an event) pursuant to any agreement, arrangement, or understanding (whether or not in writing) or upon the exercise of conversion rights, exchange rights, other rights, warrants, or options, or otherwise; provided, however, that a Person shall not be deemed the Beneficial Owner of, or to "beneficially own," (i) securities tendered pursuant to a tender or exchange offer made by such Person or any of such Person's Affiliates or Associates until such tendered securities are accepted for purchase or exchange or (ii) securities issuable upon exercise of Exempt Rights; or

(c) such Person or any of such Person's Affiliates or Associates (i) has any agreement, arrangement, or understanding (whether or not in writing) with any other Person (or any Affiliate or Associate thereof) that beneficially owns such securities for the purpose of acquiring, holding, voting (except as set forth in the proviso to subsection (a) of this definition), or disposing of such securities or (ii) is a member of a group (as that term is used in Rule 13d-5(b) of the General Rules and Regulations under the Exchange Act) that includes any other Person that beneficially owns such securities;

provided, however, that nothing in this definition shall cause a Person engaged in business as an underwriter of securities to be the Beneficial Owner of, or to "beneficially own," any securities acquired through such Person's participation in good faith in a firm commitment underwriting until the expiration of 40 days after the date of such acquisition. For purposes hereof, "voting" a security shall include voting, granting a proxy, consenting or making a request or demand relating to corporate action (including, without limitation, a demand for a stockholder list, to call a stockholder meeting or to inspect corporate books and records), or otherwise giving an authorization (within the meaning of Section 14(a) of the Exchange Act) in respect of such security.

The terms "beneficially own" and "beneficially owning" have meanings that are correlative to this definition of the term "Beneficial Owner."

1.4 "Board" means the Board of Directors of the Company.

1.5 "Cause" means (i) the willful and continued failure by the Eligible Employee to substantially perform the Eligible Employee's duties with the Employer (other than any such failure resulting from the Eligible Employee's incapacity due to physical or mental illness), or (ii) the willful engaging, not in good faith, by the Eligible Employee in conduct which is demonstrably injurious to the Company or any of its subsidiaries, monetarily or otherwise.

1.6 “Change in Control” means any of the following occurring on or after the Effective Date:

(a) any Person (other than an Exempt Person) shall become the Beneficial Owner of 20% or more of the shares of Common Stock then outstanding or 20% or more of the combined voting power of the Voting Stock of the Company then outstanding; provided, however, that no Change of Control shall be deemed to occur for purposes of this subsection (a) if such Person shall become a Beneficial Owner of 20% or more of the shares of Common Stock or 20% or more of the combined voting power of the Voting Stock of the Company solely as a result of (i) an Exempt Transaction or (ii) an acquisition by a Person pursuant to a reorganization, merger or consolidation, if, following such reorganization, merger or consolidation, the conditions described in clauses (i), (ii) and (iii) of subsection (c) of this definition are satisfied;

(b) individuals who, as of the Effective Date, constitute the Board (the “Incumbent Board”) cease for any reason to constitute at least a majority of the Board; provided, however, that any individual becoming a director subsequent to the Effective Date, whose election, or nomination for election by the Company’s shareholders, was approved by a vote of at least a majority of the directors then comprising the Incumbent Board shall be considered as though such individual were a member of the Incumbent Board; provided, further, that there shall be excluded, for this purpose, any such individual whose initial assumption of office occurs as a result of any actual or threatened Election Contest that is subject to the provisions of Rule 14a-11 of the General Rules and Regulations under the Exchange Act;

(c) the Company shall consummate a reorganization, merger, or consolidation, in each case, unless, following such reorganization, merger, or consolidation, (i) 50% or more of the then outstanding shares of common stock of the corporation resulting from such reorganization, merger, or consolidation and the combined voting power of the then outstanding Voting Stock of such corporation are beneficially owned, directly or indirectly, by all or substantially all of the Persons who were the Beneficial Owners of the outstanding Common Stock immediately prior to such reorganization, merger, or consolidation in substantially the same proportions as their ownership, immediately prior to such reorganization, merger, or consolidation, of the outstanding Common Stock, (ii) no Person (excluding any Exempt Person or any Person beneficially owning, immediately prior to such reorganization, merger, or consolidation, directly or indirectly, 20% or more of the Common Stock then outstanding or 20% or more of the combined voting power of the Voting Stock of the Company then outstanding) beneficially owns, directly or indirectly, 20% or more of the then outstanding shares of common stock of the corporation resulting from such reorganization, merger, or consolidation or the combined voting power of the then outstanding Voting Stock of such corporation, and (iii) at least a majority of the members of the board of directors of the corporation resulting from such reorganization, merger, or consolidation were members of the Incumbent Board at the time of the initial agreement or initial action by the Board providing for such reorganization, merger, or consolidation; or

(d) (i) the shareholders of the Company shall approve a complete liquidation or dissolution of the Company unless such liquidation or dissolution is approved as part of a plan of liquidation and dissolution involving a sale or disposition of all or substantially all of the assets of the Company to a corporation with respect to which, following such sale or other disposition, all of the requirements of clauses (ii)(A), (B), and (C) of this subsection (d) are satisfied, or (ii) the Company shall consummate the sale or other disposition of all or substantially all of the assets of the Company, other than to a corporation, with respect to which, following such sale or other disposition, (A) 50% or more of the then outstanding shares of common stock of such corporation and the combined voting power of the Voting Stock of such corporation is then beneficially owned, directly or indirectly, by all or substantially all of the Persons who were the Beneficial Owners of the outstanding Common Stock immediately prior to such sale or other disposition in substantially the same proportion as their ownership, immediately prior to such sale or other disposition, of the outstanding Common Stock, (B) no Person (excluding any Exempt Person and any Person beneficially owning, immediately prior to such sale or other disposition, directly or indirectly, 20% or more of the Common Stock then outstanding or 20% or more of the combined voting power of the Voting Stock of the Company then outstanding) beneficially owns, directly or indirectly, 20% or more of the then outstanding shares of common stock of such corporation and the combined voting power of the then outstanding Voting Stock of such corporation, and (C) at least a majority of the members of the board of directors of such corporation were members of the Incumbent Board at the time of the initial agreement or initial action of the Board providing for such sale or other disposition of assets of the Company.

1.7 “Code” means the Internal Revenue Code of 1986, as it may be amended from time to time.

1.8 “Common Stock” means the common stock, par value $.01 per share, of the Company.

1.9 “Company” means ConocoPhillips or any successors thereto.

1.10 “Credited Compensation” of a Severed Employee means the aggregate of the Severed Employee’s annual base salary plus his or her annual incentive compensation, each as further described below. For purposes of this definition, (a) annual base salary shall be determined immediately prior to the Severance Date (without regard to any reductions therein which constitute Good Reason) and (b) annual incentive compensation shall be deemed to equal the higher of (i) the Severed Employee’s most recently established target (determined at one hundred percent of target) for annual incentive compensation for such employee prior to such employee’s Severance Date or (ii) the average of the most recent two annual incentive compensation payments to by such Severed Employee pursuant to the Variable Cash Incentive Program or its successor program maintained by the Employer made before his or her Severance Date; provided, however, that for purposes of this clause (ii), (I) if such Severed Employee has been eligible to receive only one such annual incentive compensation payment for a period ending before his or her Severance Date, the amount of annual incentive compensation for purposes of determining Credited Compensation shall be equal to the amount of such single annual incentive compensation payment (if any), and (II) if such Severed

Employee has not been eligible for any such annual incentive compensation payment, the amount of annual incentive compensation for purposes of determining Credited Compensation shall be equal to his or her most recently established target (determined at one hundred percent of target) for annual incentive compensation for such employee prior to such employee's Severance Date.

1.11 "Effective Date" means the date first stated above as the effective date of this Plan.

1.12 "Eligible Employee" means any employee that is a Tier 1 Employee or a Tier 2 Employee.

1.13 "Employer" means the Company or any of its subsidiaries.

1.14 "Exchange Act" means the Securities Exchange Act of 1934, as amended.

1.15 "Excise Tax" shall mean the excise tax imposed by Section 4999 of the Code, together with any interest or penalties imposed with respect to such excise tax.

1.16 "Exempt Person" means any of the Employers, any employee benefit plan of any of the Employers, and any Person organized, appointed, or established by any Employer for or pursuant to the terms of any such plan.

1.17 "Exempt Rights" means any rights to purchase shares of Common Stock or other Voting Stock of the Company if at the time of the issuance thereof such rights are not separable from such Common Stock or other Voting Stock (*i.e.*, are not transferable otherwise than in connection with a transfer of the underlying Common Stock or other Voting Stock), except upon the occurrence of a contingency, whether such rights exist as of the Effective Date, or are thereafter issued by the Company as a dividend on shares of Common Stock or other Voting Securities or otherwise.

1.18 "Exempt Transaction" means an increase in the percentage of the outstanding shares of Common Stock or the percentage of the combined voting power of the outstanding Voting Stock of the Company beneficially owned by any Person solely as a result of a reduction in the number of shares of Common Stock then outstanding due to the repurchase of Common Stock or Voting Stock by the Company, unless and until such time as (a) such Person or any Affiliate or Associate of such Person shall purchase or otherwise become the Beneficial Owner of additional shares of Common Stock constituting 1% or more of the then outstanding shares of Common Stock or additional Voting Stock representing 1% or more of the combined voting power of the then outstanding Voting Stock, or (b) any other Person (or Persons) who is (or collectively are) the Beneficial Owner of shares of Common Stock constituting 1% or more of the then outstanding shares of Common Stock or Voting Stock representing 1% or more of the combined voting power of the then outstanding Voting Stock shall become an Affiliate or Associate of such Person.

1.19 "Good Reason" means the occurrence, on or after the date of a Change in Control, and without the Eligible Employee's written consent, of (i) the assignment to the Eligible Employee of duties in the aggregate that are inconsistent with the Eligible Employee's level of responsibility immediately prior to the date of the Change in Control or any diminution in the nature of the Eligible

Employee's responsibilities from those in effect immediately prior to the date of the Change in Control; (ii) a reduction by the Employer in the Eligible Employee's annual base salary or any adverse change in the Eligible Employee's aggregate annual and long term incentive compensation opportunity from that in effect immediately prior to the Change in Control which change is not pursuant to a program applicable to all comparably situated executives of the Employer; or (iii) the relocation of the Eligible Employee's principal place of employment to a location more than 50 miles from the Eligible Employee's principal place of employment immediately prior to the date of the Change in Control; provided, however, that this clause (iii) shall not be considered to be Good Reason if the Employer undertakes to pay all reasonable relocation expenses of the Eligible Employee in connection with such relocation, whether through a relocation plan, program, or policy of the Employer or otherwise.

1.20 "Gross-Up Payment" has the meaning set forth in Section 2.5 hereof.

1.21 "Parachute Value" of a Payment shall mean the present value as of the date of the change of control for purposes of Section 280G of the Code of the portion of such Payment that constitutes a "parachute payment" under Section 280G(b)(2), as determined by the Accounting Firm for purposes of determining whether and to what extent the Excise Tax will apply to such Payment.

1.22 "Payment" shall mean any payment or distribution in the nature of compensation (within the meaning of Section 280G(b)(2) of the Code) to or for the benefit of an Eligible Employee, whether paid or payable pursuant to this Plan or otherwise, by any Employer or by a Person that is a party to the Change in Control.

1.23 "Person" means any individual, firm, corporation, partnership, association, trust, unincorporated organization, or other entity.

1.24 "Plan" means the ConocoPhillips Key Employee Change in Control Severance Plan, as set forth herein, as it may be amended from time to time.

1.25 "Plan Administrator" means the person or persons appointed from time to time by the Board, which appointment may be revoked at any time by the Board.

1.26 "Public Offering" means the initial sale of common equity securities of the Company pursuant to an effective registration statement (other than a registration on Form S-4 or S-8 or any successor or similar forms) filed under the Securities Act of 1933.

1.27 "Retirement Plans" means the ConocoPhillips Retirement Plan and the ConocoPhillips Key Employee Supplemental Retirement Plan.

1.28 "Safe Harbor Amount" means, with respect to an Eligible Employee, 2.99 times the Eligible Employee's "base amount," within the meaning of Section 280G(b)(3) of the Code.

1.29 “Severance” means the termination of an Eligible Employee’s employment with the Employer on or within two years following the date of a Change in Control, (i) by the Employer other than for Cause, or (ii) by the Eligible Employee for Good Reason. An Eligible Employee will not be considered to have incurred a Severance if his employment is discontinued by reason of the Eligible Employee’s death or a physical or mental condition causing such Eligible Employee’s inability to substantially perform his duties with the Employer and entitling him or her to benefits under any long-term sick pay or disability income policy or program of the Employer. Furthermore, an Eligible Employee will not be considered to have incurred a Severance if employment with the Employer is discontinued after the Eligible Employee has been offered employment with another employer that has purchased a subsidiary or division of the Company or all or substantially all of the assets of an a subsidiary or division of the Company and the offer of employment from the other employer is at the same or greater salary and the same or greater target bonus as the Eligible Employee has at that time from the Employer. Notwithstanding anything herein to the contrary, Good Reason shall not be deemed to have occurred unless the Company shall have been given (1) written notice of the Eligible Employee’s assertion that an event constituting Good Reason has occurred, which notice shall be given not less than 30 days prior to the Severance Date to which such notice relates, and (2) a reasonable opportunity to cure such occurrence during such 30-day period.

1.30 “Severance Date” means the date on which an Eligible Employee incurs a Severance.

1.31 “Severance Pay” means the payment determined pursuant to Section 2.1 hereof.

1.32 “Severed Employee” means an Eligible Employee who has incurred a Severance.

1.33 “Tier 1 Employee” means any employee of the Employer who is in salary grade 26 or above (under the salary grade schedule of the Company on the Effective Date, with appropriate adjustment for any subsequent change in such salary grade schedule), at or subsequent to the time of the Change in Control.

1.34 “Tier 2 Employee” means any employee of the Employer, other than a Tier 1 Employee, who is in salary grade 23 or above (under the salary grade schedule of the Company on the Effective Date, with appropriate adjustment for any subsequent change in such salary grade schedule) at or subsequent to the time of the Change in Control.

1.35 “Value” of a Payment shall mean the economic present value of a Payment as of the date of the change of control for purposes of Section 280G of the Code, as determined by the Accounting Firm using the discount rate required by Section 280G(d)(4) of the Code.

1.36 “Voting Stock” means, with respect to a corporation, all securities of such corporation of any class or series that are entitled to vote generally in the election of directors of such corporation (excluding any class or series that would be entitled so to vote by reason of the occurrence of any contingency, so long as such contingency has not occurred).

SECTION 2. BENEFITS.

2.1 Subject to Section 2.9, each Severed Employee shall be entitled to receive Severance Pay equal to the sum of (a) and (b). For this purpose, (a) is the Severed Employee's Credited Compensation, multiplied by (i) 3, in the case of a Tier 1 Employee or (ii) 2 in the case of a Tier 2 Employee and (b) is the present value, determined as of the Severed Employee's Severance Date, of the increase in benefits under the Retirement Plans that would result if the Severed Employee was credited with the following number of additional years of age and service under the Retirement Plans: (i) 3, in the case of a Tier 1 Employee or (ii) 2, in the case of a Tier 2 Employee. Present value shall be determined based on the assumptions utilized under the ConocoPhillips Retirement Plan for purposes of determining contributions under Code Section 412 for the most recently completed plan year.

2.2 Severance Pay (as well as any amount payable pursuant to Section 2.6 hereof) shall be paid to an eligible Severed Employee in a cash lump sum, as soon as practicable following the Severance Date, but in no event later than 5 business days immediately following the date the Severed Employee's release, described in Section 2.9, becomes irrevocable.

2.3 Subject to Section 2.9, for a period of (a) 36 months, in the case of a Tier 1 Employee or (b) 24 months, in the case of a Tier 2 Employee, beginning the first of the month following the termination of active employee benefits, the Company shall arrange to provide the Severed Employee and his dependents benefits similar to those the Severed Employee and his dependents had immediately prior to the Severed Employee's Severance Date. Only those dependents who were eligible for coverage on the Severed Employee's Severance Date may be covered thereafter, but no amendment to any plan or program providing these benefits made after the Severed Employee's Severance Date shall prevent eligibility for dependents who would otherwise have been eligible for coverage on the Severed Employee's Severance Date. These benefits will be provided at no greater cost to the Severed Employee than active employee rates for the plan year of coverage provided the benefits continue to be offered by the Company to active employees and the Severed Employee and his dependents meet the same eligibility criteria for the benefits as an active employee and dependents of an active employee. Depending on coverages prior to the Severed Employee's Severance Date, these benefits could include the following, but do not include any other benefits offered by the Company: Life Insurance, which includes Basic, Executive Basic, Supplemental, and Dependent Life; Personal Accident Insurance; Medical (Primary PPO and Traditional Options); and Dental (CP Dental Option). Severed employees may also continue Long Term Care and Executive Life directly through the vendor to be paid for by the Severed Employee. If a Severed Employee is covered by any other Medical Option prior to the Severed Employee's Severance Date, the Severed Employee will be covered under the Primary PPO Option or the Traditional Option for medical benefits, at the Severed Employee's choice, as soon as possible after the Severed Employee's Severance Date. If a Severed Employee is covered by any other Dental Option prior to the Severed Employee's Severance Date, the Severed Employee will be covered under the CP Dental Option for dental benefits as soon as possible after the Severed Employee's Severance Date. While as an active employee the Severed Employee may have been able to make employee contributions or pay premiums for certain coverage through a pre-tax salary reduction arrangement, that will not continue after the Severed Employee's Severance Date. The cost of these benefits will not be adjusted to reflect that the Severed Employee's cost will no longer be pre-tax. All other active employee benefits, not specifically mentioned above, are excluded, although if any of the benefits specifically mentioned above are replaced with a similar benefit after the Severed Employee's Severance Date, such replacement benefits are to be considered as mentioned specifically above even though their names, terms, and conditions may have been changed. Such benefits shall not be provided (except to the extent as may be required by law) during any period when the Severed Employee is eligible to receive such benefits from another employer or from an Employer or if the Severed Employee has resumed working for an Employer. The Severed Employee is obligated to inform the Company when or if they become eligible to receive such benefits from another employer.

2.4 Upon Change in Control, each Eligible Employee shall immediately become fully vested in all outstanding equity awards and shall not thereafter be forfeitable for any reason (except that options shall expire and be cancelled ten years from the date of their grant). Any options granted to the Eligible Employee shall be exercisable at the times set forth in the applicable award documents. Each such option shall remain outstanding until ten years from the date of grant, notwithstanding any provision of the option grant or any plan under which the option may have been granted to the contrary. Restrictions existing on any restricted stock or restricted stock units granted to the Eligible Employee shall immediately lapse, and any such stock held in escrow shall be released. Any stock or other value payable from grants of restricted stock or restricted stock units shall be delivered or paid to the Eligible Employee as soon as practicable following the Change in Control, but in no event later than 5 business days immediately following the Change in Control.

2.5 (a) Anything in this Plan to the contrary notwithstanding and except as set forth below, in the event it shall be determined that any Payment to an Eligible Employee would be subject to the Excise Tax, then the Eligible Employee shall be entitled to receive an additional payment (the "Gross-Up Payment") in an amount such that, after payment by the Eligible Employee of all taxes (and any interest or penalties imposed with respect to such taxes), including, without limitation, any income taxes (and any interest and penalties imposed with respect thereto) and Excise Tax imposed upon the Gross-Up Payment, the Eligible Employee retains an amount of the Gross-Up Payment equal to the Excise Tax imposed upon the Payments. Notwithstanding the foregoing provisions of this Section 2.5(a), if it shall be determined that an Eligible Employee is entitled to the Gross-Up Payment, but that the Parachute Value of all Payments does not exceed 110% of the Safe Harbor Amount, then no Gross-Up Payment shall be made to the Eligible Employee and the amounts payable under this Plan shall be reduced so that the Parachute Value of all Payments, in the aggregate, equals the Safe Harbor Amount. The reduction of the amounts payable hereunder, if applicable, shall be made by first reducing the payments under Section 2.1, unless an alternative method of reduction is elected by the Eligible Employee, and in any event shall be made in such a manner as to maximize the Value of all Payments actually made to the Eligible Employee. For purposes of reducing the Payments to the Safe Harbor Amount, only amounts payable under this Plan (and no other Payments) shall be reduced. If the reduction of the amount payable under this Plan to an Eligible Employee would not result in a reduction of the Parachute Value of all Payments to the Safe Harbor Amount, no amounts payable to the Eligible Employee under the Plan shall be reduced pursuant to this Section 2.5(a). The Company's obligation to make Gross-Up Payments to an Eligible Employee under this Section 2.5 shall not be conditioned upon the Eligible Employee's termination of employment.

(b) Subject to the provisions of Section 2.5(c), all determinations required to be made under this Section 2.5, including whether and when a Gross-Up Payment is required, the amount of such Gross-Up Payment and the assumptions to be utilized in arriving at such determination, shall be made by a nationally recognized certified public accounting firm designated by the Plan Administrator (the "Accounting Firm"). The Accounting Firm shall provide detailed supporting calculations both to the Company and each Eligible Employee Eligible Employee within 15 business days of the receipt of notice from the Eligible Employee that there has been a Payment or such earlier time as is requested by the Company. All fees and expenses of the Accounting Firm shall be borne solely by the Company. Any Gross-Up Payment, as determined pursuant to this Section 2.5, shall be paid by the Company to the Eligible Employee within 5 days of the receipt of the Accounting Firm's determination. Any determination by the Accounting Firm shall be binding upon the Company and the Eligible Employee. As a result of the uncertainty in the application of Section 4999 of the Code at the time of the initial determination by the Accounting Firm hereunder, it is possible that Gross-Up Payments that will not have been made by the Company should have been made (the "Underpayment"), consistent with the calculations required to be made hereunder. In the event the Company exhausts its remedies pursuant to Section 2.5(c) and the Eligible Employee thereafter is required to make a payment of any Excise Tax, the Accounting Firm shall determine the amount of the Underpayment that has occurred and any such Underpayment shall be promptly paid by the Company to or for the benefit of the Eligible Employee.

(c) As a condition to being entitled to Gross-Up Payment hereunder, each Eligible Employee shall be required to notify the Company in writing of any claim by the Internal Revenue Service that, if successful, would require the payment by the Company of the Gross-Up Payment. Such notification shall be given as soon as practicable, but no later than 10 business days after the Eligible Employee is informed in writing of such claim. The Eligible Employee shall apprise the Company of the nature of such claim and the date on which such claim is requested to be paid. The Eligible Employee shall not pay such claim prior to the expiration of the 30-day period following the date on which the Eligible Employee gives such notice to the Company (or such shorter period ending on the date that any payment of taxes with respect to such claim is due). If the Company notifies the Eligible Employee in writing prior to the expiration of such period that the Company desires to contest such claim, the Eligible Employee shall:

(i) give the Company any information reasonably requested by the Company relating to such claim,

(ii) take such action in connection with contesting such claim as the Company shall reasonably request in writing from time to time, including, without limitation, accepting legal representation with respect to such claim by an attorney reasonably selected by the Company,

(iii) cooperate with the Company in good faith in order effectively to contest such claim, and

(iv) permit the Company to participate in any proceedings relating to such claim;

provided, however, that the Company shall bear and pay directly all costs and expenses (including additional interest and penalties) incurred in connection with such contest, and shall indemnify and hold the Eligible Employee harmless, on an after-tax basis, for any Excise Tax or income tax (including interest and penalties) imposed as a result of such representation and payment of costs and expenses. Without limitation on the foregoing provisions of this Section 2.5(c), the Company shall control all proceedings taken in connection with such contest, and, at its sole discretion, may pursue or forgo any and all administrative appeals, proceedings, hearings and conferences with the applicable taxing authority in respect of such claim and may, at its sole discretion, either direct the Eligible Employee to pay the tax claimed and sue for a refund or contest the claim in any permissible manner, and the Eligible Employee agrees to prosecute such contest to a determination before any administrative tribunal, in a court of initial jurisdiction and in one or more appellate courts, as the Company shall determine; provided, however, that, if the Company directs the Eligible Employee to pay such claim and sue for a refund, the Company shall make such payment and shall indemnify and hold the Eligible Employee harmless, on an after-tax basis, from any Excise Tax or income tax (including interest or penalties) imposed with respect to such payment or with respect to any imputed income in connection with such payment; and provided, further, that any extension of the statute of limitations relating to payment of taxes for the taxable year of the Eligible Employee with respect to which such contested amount is claimed to be due is limited solely to such contested amount. Furthermore, the Company's control of the contest shall be limited to issues with respect to which the Gross-Up Payment would be payable hereunder, and the Eligible Employee shall be entitled to settle or contest, as the case may be, any other issue raised by the Internal Revenue Service or any other taxing authority.

(d) If, after the Company has made a Gross-Up Payment or a payment pursuant to Section 2.5(c), an Eligible Employee becomes entitled to receive any refund with respect to the Excise Tax to which such Gross-Up Payment relates or with respect to the claim to which such payment relates, the Eligible Employee shall (subject to the Company's complying with the requirements of Section 2.5(c), if applicable) promptly pay to the Company the amount of such refund (together with any interest paid or credited thereon after taxes applicable thereto). If, after the Company has paid any amount pursuant to Section 2.5(c), a determination is made that the Eligible Employee shall not be entitled to any refund with respect to such claim and the Company does not notify the Eligible Employee in writing of its intent to contest such denial of refund prior to the expiration of 30 days after such determination, then the amount of such payment shall offset, to the extent thereof, the amount of Gross-Up Payment required to be paid.

(e) Notwithstanding any other provision of this Section 2.5, the Company may, in its sole discretion, withhold and pay over to the Internal Revenue Service or any other applicable taxing authority, for the benefit of any Eligible Employee, all or any portion of any Gross-Up Payment, and each Eligible Employee shall be required to consent to such withholding as a condition to being entitled to any Gross-Up Payment.

2.6 Each Severed Employee shall be entitled to receive the employee’s full salary through the Severance Date and, subject to Section 2.9 but notwithstanding any provision of the Company’s Variable Cash Incentive Program or similar annual bonus incentive plan to the contrary, a cash lump sum amount equal to a pro rata portion to the Severance Date of the aggregate value of the annual incentive compensation award to such Severed Employee for the then uncompleted fiscal year under such plan, calculated by multiplying the average of the last two annual awards paid to the Severed Employee, by the fraction obtained by dividing the number of full months and any fractional portion of a month during said fiscal year through the Severance Date by 12; provided, however, that for purposes of this clause, (I) if such Severed Employee has been eligible to receive only one such annual incentive compensation payment for a period ending before his or her Severance Date, the amount of annual incentive compensation for purposes of determining this cash lump sum shall be equal to the amount of such single annual incentive compensation payment (if any), and (II) if such Severed Employee has not been eligible for any such annual incentive compensation payment, the amount of annual incentive compensation for purposes of determining this cash lump sum shall be equal to his or her most recently established target (determined at one hundred percent of target) for annual incentive compensation for such employee prior to such employee’s Severance Date.

2.7 The Company will pay to each Eligible Employee all reasonable legal fees and expenses incurred by such Eligible Employee in pursuing any claim under the Plan, unless the applicable finder of fact determines that the Eligible Employee’s claim was frivolous or not maintained in good faith.

2.8 The Company shall be entitled to withhold and/or to cause to be withheld from amounts to be paid to the Severed Employee hereunder any federal, state, or local withholding or other taxes or charges which it is from time to time required to withhold.

2.9 No Severed Employee shall be eligible to receive Severance Pay or other benefits under the Plan unless he or she first executes a written release substantially in the form attached as Exhibit A hereto (or, if the Severed Employee was not a United States employee, a similar release which is in accordance with the applicable laws in the relevant jurisdiction) and, to the extent such release is revocable by its terms, only if the Severed Employee does not revoke it.

SECTION 3. PLAN ADMINISTRATION.

3.1 The Plan Administrator shall administer the Plan and may interpret the Plan, prescribe, amend, and rescind rules and regulations under the Plan and make all other determinations necessary or advisable for the administration of the Plan, subject to all of the provisions of the Plan.

3.2 In the event of a claim by an Eligible Employee as to the amount or timing of any payment or benefit, such Eligible Employee shall present the reason for his or her claim in writing to the Plan Administrator. The Plan Administrator shall, within 14 days after receipt of such written claim, send a written notification to the Eligible Employee as to its disposition. Except as provided in the preceding portion of this Section 3.2, all disputes under this Plan shall be settled exclusively by binding arbitration in Houston, Texas, in accordance with the rules of the American Arbitration Association then in effect. Judgment may be entered on the arbitrator's award in any court having jurisdiction.

3.3 The Plan Administrator may delegate any of its duties hereunder to such person or persons from time to time as it may designate.

3.4 The Plan Administrator is empowered, on behalf of the Plan, to engage accountants, legal counsel, and such other personnel as it deems necessary or advisable to assist it in the performance of its duties under the Plan. The functions of any such persons engaged by the Plan Administrator shall be limited to the specified services and duties for which they are engaged, and such persons shall have no other duties, obligations or responsibilities under the Plan. Such persons shall exercise no discretionary authority or discretionary control respecting the management of the Plan. All reasonable expenses thereof shall be borne by the Employer.

SECTION 4. DURATION; AMENDMENT; AND TERMINATION.

4.1 This Plan shall be effective on the Effective Date. If a Change in Control has not occurred, this Plan shall continue in effect unless and until it is terminated as provided in Section 4.2. If a Change in Control occurs, this Plan shall continue in full force and effect and shall not terminate or expire until after all Eligible Employees who become or may become entitled to any payments hereunder shall have received such payments in full and all adjustments required to be made pursuant to Section 2 have been made.

4.2 (a) If a Change in Control has not occurred, this Plan may be amended from time to time during its term by the Company acting through its Board of Directors or, to the extent authorized by the Board of Directors, its officers, provided that any such amendment which shall in any manner reduce, diminish, or otherwise adversely affect any benefit which is or may at any time in the future become payable hereunder, or any such amendment which shall alter the definition of Change in Control shall be made effective not less than two years after the action of the Company authorizing such amendment, and in no event shall any such amendment take effect prior to October 1, 2006, unless, and then only to the extent that such amendment is or becomes necessary in order to assure continued compliance by this Plan with any applicable state or federal law or regulation.

(b) This Plan shall not terminate prior to October 1, 2006. On or after October 1, 2004, the Company may, by action of its Board of Directors, terminate this Plan, provided, however, that the effective date of such termination shall be not less than two years from the date of such Board action. Provided further that in the event a Change in Control shall occur prior to the effective date of termination, the provisions of Section 4.2(c) shall apply.

(c) If a Change in Control shall occur while this Plan is in effect, no then-pending amendment or termination shall take effect, this Plan shall remain in full force and effect as at the Change in Control, and this Plan shall terminate automatically without further action on behalf of the Company immediately following the making of all payments to Eligible Employees under this Plan.

SECTION 5. GENERAL PROVISIONS.

5.1 Except as otherwise provided herein or by law, no right or interest of any Eligible Employee under the Plan shall be assignable or transferable, in whole or in part, either directly or by operation of law or otherwise, including without limitation by execution, levy, garnishment, attachment, pledge, or in any manner; no attempted assignment or transfer thereof shall be effective; and no right or interest of any Eligible Employee under the Plan shall be liable for, or subject to, any obligation or liability of such Eligible Employee. When a payment is due under this Plan to a Severed Employee who is unable to care for his or her affairs, payment may be made directly to his or her legal guardian or personal representative.

5.2 If any Employer is obligated by law or by contract to pay severance pay, a termination indemnity, notice pay, or the like, to a Severed Employee, or if any Employer is obligated by law to provide advance notice of separation ("Notice Period") to a Severed Employee, then any Severance Pay hereunder to such Severed Employee shall be reduced by the amount of any such severance pay, termination indemnity, notice pay, or the like, as applicable, and by the amount of any compensation received during any Notice Period. This provision specifically includes any payments or obligations under the Conoco Inc. Key Employee Severance Plan, as amended and restated effective October 1, 2001, and as subsequently amended, or under the ConocoPhillips Severance Pay Plan, as effective March 13, 2004, and as subsequently amended, or under the ConocoPhillips Executive Severance Plan, as effective October 1, 2004, and as subsequently amended. Furthermore, if an Eligible Employee has willful and bad faith conduct demonstrably injurious to Company or its subsidiaries, monetarily or otherwise, after receiving Severance Pay, the Company may offset an amount equal to such Severance Pay against any other amounts due from other plans or programs, unless otherwise required by law.

5.3 Neither the establishment of the Plan, nor any modification thereof, nor the creation of any fund, trust, or account, nor the payment of any benefits shall be construed as giving any Eligible Employee, or any person whomsoever, the right to be retained in the service of the Employer, and all

Eligible Employees shall remain subject to discharge to the same extent as if the Plan had never been adopted.

5.4 If any provision of this Plan shall be held invalid or unenforceable, such invalidity or unenforceability shall not affect any other provisions hereof, and this Plan shall be construed and enforced as if such provisions had not been included.

5.5 This Plan shall be binding upon the heirs, executors, administrators, successors, and assigns of the parties, including each Eligible Employee, present and future, and any successor to the Employer.

5.6 The headings and captions herein are provided for reference and convenience only, shall not be considered part of the Plan, and shall not be employed in the construction of the Plan.

5.7 The Plan shall not be funded. No Eligible Employee shall have any right to, or interest in, any assets of any Employer that may be applied by the Employer to the payment of benefits or other rights under this Plan.

5.8 Any notice or other communication required or permitted pursuant to the terms hereof shall have been duly given when delivered or mailed by United States Mail, first-class, postage prepaid, addressed to the intended recipient at his, her or its last known address.

5.9 This Plan shall be construed and enforced according to the laws of the State of Delaware.

CONOCOPHILLIPS

By: /s/ Carin S. Knickel Dated: 11/1/2004

Carin S. Knickel
Vice President, Human Resources

Exhibit A

WAIVER AND RELEASE OF CLAIMS

In consideration of, and subject to, the payments to be made to me by ConocoPhillips, a Delaware corporation (the “Company”) or any of its subsidiaries, pursuant to the ConocoPhillips Key Employee Change in Control Severance Plan (the “Plan”), which I acknowledge that I would not otherwise be entitled to receive, I hereby waive any claims I may have for employment or re-employment by the Company or any subsidiary or parent of the Company after the date hereof, and I further agree to and do release and forever discharge the Company or any subsidiary or parent of the Company, and their respective past and present officers, directors, shareholders, employees, and agents from any and all claims and causes of action, known or unknown, arising out of or relating to my employment with the Company or any subsidiary or parent of the Company, or the termination thereof, including, but not limited to, wrongful discharge, breach of contract, tort, fraud, the Civil Rights Acts, Age Discrimination in Employment Act, Employee Retirement Income Security Act, Americans with Disabilities Act, or any other federal, state, or local legislation or common law relating to employment or discrimination in employment or otherwise.

Notwithstanding the foregoing or any other provision hereof, nothing in this Waiver and Release of Claims shall adversely affect (i) my rights under the Plan; (ii) my rights to benefits other than severance benefits under plans, programs, and arrangements of the Company or any subsidiary or parent of the Company which are accrued but unpaid as of the date of my termination; or (iii) my rights to indemnification under any indemnification agreement, applicable law and the certificates of incorporation and bylaws of the Company and any subsidiary or parent of the Company, and my rights under any director’s and officers’ liability insurance policy covering me.

I acknowledge that I have signed this Waiver and Release of Claims voluntarily, knowingly, of my own free will and without reservation or duress and that no promises or representations have been made to me by any person to induce me to do so other than the promise of payment set forth in the first paragraph above and the Company’s acknowledgement of my rights reserved under the second paragraph above.

Signature: ______________________________ Dated: ______________________________

Exhibit 10.2

CONOCOPHILLIPS
EXECUTIVE SEVERANCE PLAN

(Effective October 1, 2004)

Effective October 1, 2004, the Company adopts this the ConocoPhillips Executive Severance Plan (the “Plan”) for the benefit of certain employees of the Company and its subsidiaries.

All capitalized terms used herein are defined in Section 1 hereof. This Plan is intended to be a plan maintained primarily for the purpose of providing deferred compensation for a select group of management or highly compensated employees, within the meaning of Title I of the Employee Retirement Income Security Act of 1974, as amended and shall be interpreted in a manner consistent with such intention.

SECTION 1. DEFINITIONS. As hereinafter used:

1.1 “Board” means the Board of Directors of the Company.

1.2 “Cause” means (i) the willful and continued failure by the Eligible Employee to substantially perform the Eligible Employee’s duties with the Employer (other than any such failure resulting from the Eligible Employee’s incapacity due to physical or mental illness), or (ii) the willful engaging, not in good faith, by the Eligible Employee in conduct which is demonstrably injurious to the Company or any of its subsidiaries, monetarily or otherwise.

1.3 “Code” means the Internal Revenue Code of 1986, as it may be amended from time to time.

1.4 “Company” means ConocoPhillips or any successors thereto.

1.5 “Credited Compensation” of a Severed Employee means the aggregate of the Severed Employee’s annual base salary plus his or her annual incentive compensation, each as further described below. For purposes of this definition, (a) annual base salary shall be determined immediately prior to the Severance Date and (b) annual incentive compensation shall be deemed to equal the Severed Employee’s most recently established target (determined at one hundred percent of target) for annual incentive compensation for such employee prior to such employee’s Severance Date pursuant to the Variable Cash Incentive Program or its successor program maintained by the Employer.

1.6 “Effective Date” means the date first stated above as the effective date of this Plan.

1.7 “Eligible Employee” means any employee that is a Tier 1 Employee or a Tier 2 Employee, other than those employees who are listed on Exhibit B.

1.8 “Employer” means the Company or any of its subsidiaries.

1.9 “Person” means any individual, firm, corporation, partnership, association, trust, unincorporated organization, or other entity.

1.10 “Plan” means the ConocoPhillips Executive Severance Plan, as set forth herein, as it may be amended from time to time.

1.11 “Plan Administrator” means the person or persons appointed from time to time by the Board, which appointment may be revoked at any time by the Board.

1.12 “Retirement Plans” means the ConocoPhillips Retirement Plan and the ConocoPhillips Key Employee Supplemental Retirement Plan.

1.13 “Severance” means the termination of an Eligible Employee’s employment with the Employer by the Employer other than for Cause. An Eligible Employee will not be considered to have incurred a Severance if his employment is discontinued by reason of the Eligible Employee’s death or a physical or mental condition causing such Eligible Employee’s inability to substantially perform his duties with the Employer and entitling him or her to benefits under any long-term sick pay or disability income policy or program of the Employer. Furthermore, an Eligible Employee will not be considered to have incurred a Severance if employment with the Employer is discontinued after the Eligible Employee has been offered employment with another employer that has purchased a subsidiary or division of the Company or all or substantially all of the assets of an a subsidiary or division of the Company and the offer of employment from the other employer is at the same or greater salary and the same or greater target bonus as the Eligible Employee has at that time from the Employer. Still further, an Eligible Employee will not be considered to have incurred a Severance if employment with the Employer is discontinued and the Eligible Employee is also eligible for payments under the ConocoPhillips Key Employee Change in Control Severance Plan, effective October 1, 2004, or as subsequently amended, or under the Conoco Inc. Key Employee Severance Plan, as amended and restated effective October 1, 2001, and as subsequently amended.

1.14 “Severance Date” means the date on which an Eligible Employee incurs a Severance.

1.15 “Severance Pay” means the payment determined pursuant to Section 2.1 hereof.

1.16 “Severed Employee” means an Eligible Employee who has incurred a Severance.

1.17 “Tier 1 Employee” means any employee of the Employer who is in salary grade 26 or above (under the salary grade schedule of the Company on the Effective Date, with appropriate adjustment for any subsequent change in such salary grade schedule) on the Severance Date.

1.18 “Tier 2 Employee” means any employee of the Employer, other than a Tier 1 Employee, who is in salary grade 23 or above (under the salary grade schedule of the Company on the Effective Date, with appropriate adjustment for any subsequent change in such salary grade schedule) on the Severance Date.

SECTION 2. BENEFITS.

2.1 Subject to Section 2.7, each Severed Employee shall be entitled to receive Severance Pay equal to the sum of (a) and (b). For this purpose, (a) is the Severed Employee’s Credited Compensation, multiplied by (i) 2, in the case of a Tier 1 Employee or (ii) 1.5 in the case of a Tier 2 Employee and (b) is the present value, determined as of the Severed Employee’s Severance Date, of the increase in benefits under the Retirement Plans that would result if the Severed Employee was credited with the following number of additional years of age and service under the Retirement Plans: (i) 2, in the case of a Tier 1 Employee or (ii) 1.5, in the case of a Tier 2 Employee. Present value shall be determined based on the assumptions utilized under the ConocoPhillips Retirement Plan for purposes of determining contributions under Code Section 412 for the most recently completed plan year. For purposes of Employer compensation plans, programs, and arrangements, each Severed Employee shall be considered to have been laid off by the Employer.

2.2 Severance Pay (as well as any amount payable pursuant to Section 2.4 hereof) shall be paid to an eligible Severed Employee by crediting the account of the Severed Employee in the ConocoPhillips Key Employee Deferred Compensation Plan, as soon as practicable following the later of the Severance Date and the date the Severed Employee’s release, described in Section 2.7, becomes irrevocable; provided, however, that a Severed Employee not on the U.S. payroll shall instead be paid directly rather than by crediting of an account in the ConocoPhillips Key Employee Deferred Compensation Plan. Amounts credited to the ConocoPhillips Key Employee Deferred Compensation Plan shall be subject to the terms and conditions of the ConocoPhillips Key Employee Deferred Compensation Plan. Within 30 days of becoming eligible for benefits under this Plan, each Eligible Employee shall make an election under the ConocoPhillips Key Employee Deferred Compensation Plan as to the timing of receipt of any amounts under the ConocoPhillips Key Employee Deferred Compensation Plan derived from benefits arising from this Plan.

2.3 Subject to Section 2.7, for a period of (a) 24 months, in the case of a Tier 1 Employee or (b) 18 months, in the case of a Tier 2 Employee, beginning the first of the month following the termination of active employee benefits, the Company shall arrange to provide the Severed Employee and his eligible dependents benefits similar to those the Severed Employee and his eligible dependents had immediately prior to the Severed Employee’s Severance Date. These benefits will be provided at no greater cost to the Severed Employee than active employee rates for the plan year of coverage provided the benefits continue to be offered by the Company to active employees and the Severed Employee and his eligible dependents meet the same eligibility criteria for the benefits as an active employee and dependents of an active employee. Depending on coverages prior to the Severed Employee’s Severance Date, these benefits could include the following, but do not include any other benefits offered by the Company: Life Insurance, which includes Basic, Executive Basic, Supplemental, and Dependent Life; Personal Accident

Insurance; Medical (Primary PPO and Traditional Options); and Dental (CP Dental Option). Severed employees may also continue Long Term Care and Executive Life directly through the vendor to be paid for by the Severed Employee. If a Severed Employee is covered by any other Medical Option prior to the Severed Employee's Severance Date, the Severed Employee will be covered under the Primary PPO Option or the Traditional Option for medical benefits, at the Severed Employee's choice, as soon as possible after the Severed Employee's Severance Date. If a Severed Employee is covered by any other Dental Option prior to the Severed Employee's Severance Date, the Severed Employee will be covered under the CP Dental Option for dental benefits as soon as possible after the Severed Employee's Severance Date. While as an active employee the Severed Employee may have been able to make employee contributions or pay premiums for certain coverage through a pre-tax salary reduction arrangement, that will not continue after the Severed Employee's Severance Date. The cost of these benefits will not be adjusted to reflect that the Severed Employee's cost will no longer be pre-tax. All other active employee benefits, not specifically mentioned above, are excluded, although if any of the benefits specifically mentioned above are replaced with a similar benefit after the Severed Employee's Severance Date, such replacement benefits are to be considered as mentioned specifically above even though their names, terms, and conditions may have been changed. Such benefits shall not be provided (except to the extent as may be required by law) during any period when the Severed Employee is eligible to receive such benefits from another employer or from an Employer or if the Severed Employee has resumed working for an Employer. The Severed Employee is obligated to inform the Company when or if they become eligible to receive such benefits from another employer.

2.4 Each Severed Employee shall be entitled to receive the employee's full salary through the Severance Date and, subject to Section 2.7 but notwithstanding any provision of the Company's Variable Cash Incentive Program or similar annual bonus incentive plan to the contrary, a cash lump sum amount equal to a pro rata portion to the Severance Date of the aggregate value of the annual incentive compensation award to such Severed Employee for the then uncompleted fiscal year under such plan, such aggregate value being deemed to equal the Severed Employee's most recently established target (determined at one hundred percent of target) for annual incentive compensation for such employee prior to such employee's Severance Date pursuant to the Variable Cash Incentive Program (or similar annual bonus incentive plan) or its successor program maintained by the Employer.

2.5 Each party to any dispute concerning this Plan shall be responsible for that party's own legal fees and expenses; provided, however, that the arbitrator appointed pursuant to Section 3.2 of this Plan may award reasonable legal fees and expenses to an Eligible Employee if the arbitrator determines that the Company's denial of the claim of the Eligible Employee was not reasonable.

2.6 The Company shall be entitled to withhold and/or to cause to be withheld from amounts to be paid to the Severed Employee hereunder any federal, state, or local withholding or other taxes or charges which it is from time to time required to withhold.

2.7 No Severed Employee shall be eligible to receive Severance Pay or other benefits under the Plan unless he or she first executes a written release substantially in the form attached as Exhibit A hereto (or, if the Severed Employee was not a United States employee, a similar release which is in accordance with the applicable laws in the relevant jurisdiction) and, to the extent such release is revocable by its terms, only if the Severed Employee does not revoke it, and unless he or she also, at the request of the Company, executes a written agreement not to compete with the Company, with such terms and conditions as may be proposed by the Company at the time.

SECTION 3. PLAN ADMINISTRATION.

3.1 The Plan Administrator shall administer the Plan and may interpret the Plan, prescribe, amend, and rescind rules and regulations under the Plan and make all other determinations necessary or advisable for the administration of the Plan, subject to the provisions of the Plan. The Plan Administrator shall have absolute discretion and authority in carrying out its responsibilities, and all interpretations of the Plan, determinations of eligibility under the Plan, determinations to grant or deny benefits under the Plan, or findings of fact or resolutions related to the Plan and its administration that are made by the Plan Administrator shall be binding, final, and conclusive on all parties.

3.2 In the event of a claim by an Eligible Employee as to the amount or timing of any payment or benefit, such Eligible Employee shall present the reason for his or her claim in writing to the Plan Administrator. The Plan Administrator shall, within 14 days after receipt of such written claim, send a written notification to the Eligible Employee as to its disposition. Except as provided in the preceding portion of this Section 3.2, all disputes under this Plan shall be settled exclusively by binding arbitration in Houston, Texas, in accordance with the rules of the American Arbitration Association then in effect. Judgment may be entered on the arbitrator’s award in any court having jurisdiction.

3.3 The Plan Administrator may delegate any of its duties hereunder to such person or persons from time to time as it may designate.

3.4 The Plan Administrator is empowered, on behalf of the Plan, to engage accountants, legal counsel, and such other personnel as it deems necessary or advisable to assist it in the performance of its duties under the Plan. The functions of any such persons engaged by the Plan Administrator shall be limited to the specified services and duties for which they are engaged, and such persons shall have no other duties, obligations or responsibilities under the Plan. Such persons shall exercise no discretionary authority or discretionary control respecting the management of the Plan. All reasonable expenses thereof shall be borne by the Employer.

SECTION 4. DURATION; AMENDMENT; AND TERMINATION.

4.1 This Plan shall be effective on the Effective Date. This Plan shall continue in effect unless and until it is terminated as provided in Section 4.2.

4.2 This Plan may be amended from time to time during its term by the Company acting through its Board of Directors or, to the extent authorized by the Board of Directors, its officers. The Company may, by action of its Board of Directors, terminate this Plan at any time.

SECTION 5. <u>GENERAL PROVISIONS</u>.

5.1 Except as otherwise provided herein or by law, no right or interest of any Eligible Employee under the Plan shall be assignable or transferable, in whole or in part, either directly or by operation of law or otherwise, including without limitation by execution, levy, garnishment, attachment, pledge, or in any manner; no attempted assignment or transfer thereof shall be effective; and no right or interest of any Eligible Employee under the Plan shall be liable for, or subject to, any obligation or liability of such Eligible Employee. When a payment is due under this Plan to a Severed Employee who is unable to care for his or her affairs, payment may be made directly to his or her legal guardian or personal representative.

5.2 If any Employer is obligated by law or by contract to pay severance pay, a termination indemnity, notice pay, or the like, to a Severed Employee, or if any Employer is obligated by law to provide advance notice of separation ("Notice Period") to a Severed Employee, then any Severance Pay hereunder to such Severed Employee shall be reduced by the amount of any such severance pay, termination indemnity, notice pay, or the like, as applicable, and by the amount of any compensation received during any Notice Period. This provision specifically includes any payments or obligations under the ConocoPhillips Severance Pay Plan, as effective March 13, 2004, and as subsequently amended. Furthermore, if an Eligible Employee has willful and bad faith conduct demonstrably injurious to Company or its subsidiaries, monetarily or otherwise, after receiving Severance Pay, the Company may offset an amount equal to such Severance Pay against any other amounts due from other plans or programs, unless otherwise required by law.

5.3 Neither the establishment of the Plan, nor any modification thereof, nor the creation of any fund, trust, or account, nor the payment of any benefits shall be construed as giving any Eligible Employee, or any person whomsoever, the right to be retained in the service of the Employer, and all Eligible Employees shall remain subject to discharge to the same extent as if the Plan had never been adopted.

5.4 If any provision of this Plan shall be held invalid or unenforceable, such invalidity or unenforceability shall not affect any other provisions hereof, and this Plan shall be construed and enforced as if such provisions had not been included.

5.5 This Plan shall be binding upon the heirs, executors, administrators, successors, and assigns of the parties, including each Eligible Employee, present and future, and any successor to the Employer.

5.6 The headings and captions herein are provided for reference and convenience only, shall not be considered part of the Plan, and shall not be employed in the construction of the Plan.

5.7 The Plan shall not be funded. No Eligible Employee shall have any right to, or interest in, any assets of any Employer that may be applied by the Employer to the payment of benefits or other rights under this Plan.

5.8 Any notice or other communication required or permitted pursuant to the terms hereof shall have been duly given when delivered or mailed by United States Mail, first-class, postage prepaid, addressed to the intended recipient at his, her or its last known address.

5.9 This Plan shall be construed and enforced according to the laws of the State of Delaware.

CONOCOPHILLIPS

By:	/s/ Carin S. Knickel	Dated:	11/1/2004
	Carin S. Knickel		
	Vice President, Human Resources		

Exhibit A

<u>WAIVER AND RELEASE OF CLAIMS</u>

In consideration of, and subject to, the payments to be made to me by ConocoPhillips, a Delaware corporation (the “Company”) or any of its subsidiaries, pursuant to the ConocoPhillips Executive Severance Plan (the “Plan”), which I acknowledge that I would not otherwise be entitled to receive, I hereby waive any claims I may have for employment or re-employment by the Company or any subsidiary or parent of the Company after the date hereof, and I further agree to and do release and forever discharge the Company or any subsidiary or parent of the Company, and their respective past and present officers, directors, shareholders, employees, and agents from any and all claims and causes of action, known or unknown, arising out of or relating to my employment with the Company or any subsidiary or parent of the Company, or the termination thereof, including, but not limited to, wrongful discharge, breach of contract, tort, fraud, the Civil Rights Acts, Age Discrimination in Employment Act, Employee Retirement Income Security Act, Americans with Disabilities Act, or any other federal, state, or local legislation or common law relating to employment or discrimination in employment or otherwise.

Notwithstanding the foregoing or any other provision hereof, nothing in this Waiver and Release of Claims shall adversely affect (i) my rights under the Plan; (ii) my rights to benefits other than severance benefits under plans, programs, and arrangements of the Company or any subsidiary or parent of the Company which are accrued but unpaid as of the date of my termination; or (iii) my rights to indemnification under any indemnification agreement, applicable law and the certificates of incorporation and bylaws of the Company and any subsidiary or parent of the Company, and my rights under any director’s and officers’ liability insurance policy covering me.

I acknowledge that I have signed this Waiver and Release of Claims voluntarily, knowingly, of my own free will and without reservation or duress and that no promises or representations have been made to me by any person to induce me to do so other than the promise of payment set forth in the first paragraph above and the Company’s acknowledgement of my rights reserved under the second paragraph above.

Signature: ______________________________ Dated: ______________

Exhibit B

Employees Ineligible for Executive Severance Plan

Lars A. Takla

Exhibit 12

CONOCOPHILLIPS AND CONSOLIDATED SUBSIDIARIES
TOTAL ENTERPRISE

Computation of Ratio of Earnings to Fixed Charges

	Millions of Dollars		
	Nine Months Ended September 30		
		2004	2003
	(Unaudited)		
Earnings Available for Fixed Charges			
Income from continuing operations before income taxes	**$**	**10,094**	6,660
Distributions less than equity in earnings of fifty-percent-or-less-owned companies		**(447)**	(217)
Fixed charges, excluding capitalized interest*		**534**	792
	$	**10,181**	7,235
Fixed Charges			
Interest and expense on indebtedness, excluding capitalized interest	**$**	**405**	647
Capitalized interest		**340**	249
Interest portion of rental expense		**112**	126
	$	**857**	1,022
Ratio of Earnings to Fixed Charges		**11.9**	7.1

**Includes amortization of capitalized interest totaling approximately $17 million in 2004 and $19 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: 11/4/2004

/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: 11/4/2004

/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 September 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: 11/4/2004

/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