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

# FORM 10-Q

**(Mark one)**

☒ **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 1-8590**

# MURPHY OIL CORPORATION
**(Exact name of registrant as specified in its charter)**

| | |
|---|---|
| **Delaware** | **71-0361522** |
| **(State or other jurisdiction of incorporation or organization)** | **(I.R.S. Employer Identification Number)** |
| **200 Peach Street**<br>**P. O. Box 7000, El Dorado, Arkansas** | **71731-7000** |
| **(Address of principal executive offices)** | **(Zip Code)** |

**(870) 862-6411**
**(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 ☐ No

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

Number of shares of Common Stock, $1.00 par value, outstanding at September 30, 2004 was **92,008,761.**

## PART I – FINANCIAL INFORMATION

### *ITEM 1. FINANCIAL STATEMENTS*

Murphy Oil Corporation and Consolidated Subsidiaries
**CONSOLIDATED BALANCE SHEETS**
(Thousands of dollars)

| | (Unaudited) September 30, 2004 | December 31, 2003 |
|---|---|---|
| **ASSETS** | | |
| Current assets | | |
| Cash and cash equivalents | $ 955,129 | 252,425 |
| Accounts receivable, less allowance for doubtful accounts of $11,284 in 2004 and $10,735 in 2003 | 666,203 | 450,201 |
| Inventories, at lower of cost or market | | |
| Crude oil and blend stocks | 48,942 | 46,626 |
| Finished products | 161,861 | 157,078 |
| Materials and supplies | 64,502 | 66,806 |
| Prepaid expenses | 54,208 | 44,779 |
| Deferred income taxes | 32,715 | 20,940 |
| Total current assets | 1,983,560 | 1,038,855 |
| Property, plant and equipment, at cost less accumulated depreciation, depletion and amortization of $2,810,486 in 2004 and $3,472,133 in 2003 | 3,509,374 | 3,530,800 |
| Goodwill, net | 41,444 | 64,873 |
| Deferred charges and other assets | 67,776 | 78,119 |
| Total assets | $ 5,602,154 | 4,712,647 |
| **LIABILITIES AND STOCKHOLDERS’ EQUITY** | | |
| Current liabilities | | |
| Current maturities of long-term debt | $ 42,561 | 67,224 |
| Accounts payable and accrued liabilities | 938,561 | 659,609 |
| Income taxes | 160,209 | 83,493 |
| Total current liabilities | 1,141,331 | 810,326 |
| Notes payable | 1,032,213 | 1,061,410 |
| Nonrecourse debt of a subsidiary | 14,854 | 28,897 |
| Deferred income taxes | 518,435 | 421,700 |
| Asset retirement obligations | 185,443 | 252,397 |
| Accrued major repair costs | 37,083 | 20,513 |
| Deferred credits and other liabilities | 182,638 | 166,521 |
| Stockholders’ equity | | |
| Cumulative Preferred Stock, par $100, authorized 400,000 shares, none issued | — | — |
| Common Stock, par $1.00, authorized 200,000,000 shares, issued 94,613,379 shares | 94,613 | 94,613 |
| Capital in excess of par value | 510,288 | 504,809 |
| Retained earnings | 1,867,249 | 1,357,910 |
| Accumulated other comprehensive income | 91,402 | 65,246 |
| Unamortized restricted stock awards | (5,407) | — |
| Treasury stock, 2,604,618 shares of Common Stock in 2004 and 2,742,781 shares in 2003, at cost | (67,988) | (71,695) |
| Total stockholders’ equity | 2,490,157 | 1,950,883 |
| Total liabilities and stockholders’ equity | $ 5,602,154 | 4,712,647 |

See Notes to Consolidated Financial Statements, page 5.

The Exhibit Index is on page 26.

Murphy Oil Corporation and Consolidated Subsidiaries

**CONSOLIDATED STATEMENTS OF INCOME (unaudited)**

(Thousands of dollars except per share amounts)

| | Three Months Ended September 30, | | Nine Months Ended September 30, | |
|---|---|---|---|---|
| | **2004** | **2003*** | **2004** | **2003*** |
| **REVENUES** | | | | |
| Sales and other operating revenues | $ 2,262,288 | 1,251,390 | 5,987,494 | 3,684,801 |
| Gain on sale of assets | 39,100 | 10,353 | 69,900 | 59,651 |
| Interest and other income (loss) | (7,933) | 1,238 | 1,480 | 3,433 |
| Total revenues | 2,293,455 | 1,262,981 | 6,058,874 | 3,747,885 |
| **COSTS AND EXPENSES** | | | | |
| Crude oil and product purchases | 1,732,904 | 898,372 | 4,428,926 | 2,646,150 |
| Operating expenses | 174,385 | 126,540 | 522,821 | 421,035 |
| Exploration expenses, including undeveloped lease amortization | 70,118 | 44,644 | 142,476 | 88,091 |
| Selling and general expenses | 33,622 | 30,169 | 97,497 | 86,291 |
| Depreciation, depletion and amortization | 75,594 | 67,648 | 238,504 | 183,949 |
| Impairment of long-lived assets | — | 3,488 | — | 3,488 |
| Accretion of asset retirement obligations | 2,575 | 2,364 | 7,549 | 7,325 |
| Interest expense | 13,858 | 14,455 | 42,325 | 42,688 |
| Interest capitalized | (6,017) | (10,027) | (15,083) | (29,675) |
| Total costs and expenses | 2,097,039 | 1,177,653 | 5,465,015 | 3,449,342 |
| Income from continuing operations before income taxes | 196,416 | 85,328 | 593,859 | 298,543 |
| Income tax expense | 80,643 | 18,541 | 229,255 | 76,544 |
| Income from continuing operations | 115,773 | 66,787 | 364,604 | 221,999 |
| Income from discontinued operations, net of tax | 2,950 | 1,950 | 202,231 | 20,529 |
| Income before cumulative effect of change in accounting principle | 118,723 | 68,737 | 566,835 | 242,528 |
| Cumulative effect of change in accounting principle, net of tax | — | — | — | (6,993) |
| **NET INCOME** | $ 118,723 | 68,737 | 566,835 | 235,535 |
| **INCOME (LOSS) PER COMMON SHARE – BASIC** | | | | |
| Income from continuing operations | $ 1.26 | .73 | 3.96 | 2.42 |
| Income from discontinued operations | .03 | .02 | 2.20 | .22 |
| Cumulative effect of change in accounting principle | — | — | — | (.08) |
| **NET INCOME – BASIC** | $ 1.29 | .75 | 6.16 | 2.56 |
| **INCOME (LOSS) PER COMMON SHARE – DILUTED** | | | | |
| Income from continuing operations | $ 1.24 | .72 | 3.90 | 2.40 |
| Income from discontinued operations | .03 | .02 | 2.17 | .22 |
| Cumulative effect of change in accounting principle | — | — | — | (.08) |
| **NET INCOME – DILUTED** | $ 1.27 | .74 | 6.07 | 2.54 |
| Average common shares outstanding – basic | 92,005,813 | 91,850,217 | 91,972,427 | 91,799,551 |
| Average common shares outstanding – diluted | 93,568,421 | 92,848,308 | 93,365,547 | 92,612,911 |

* Reclassified to conform to 2004 presentation.

See Notes to Consolidated Financial Statements, page 5.

Murphy Oil Corporation and Consolidated Subsidiaries

**CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME (unaudited)**

(Thousands of dollars)

| | Three Months Ended September 30, | | Nine Months Ended September 30, | |
|---|---|---|---|---|
| | **2004** | **2003** | **2004** | **2003** |
| Net income | $ 118,723 | 68,737 | 566,835 | 235,535 |
| Other comprehensive income, net of tax | | | | |
| Cash flow hedges | | | | |
| Net derivative gains (losses) | (411) | (978) | 3,957 | (25,133) |
| Reclassification adjustments | (3,115) | 10,872 | (8,589) | 38,010 |
| Total cash flow hedges | (3,526) | 9,894 | (4,632) | 12,877 |
| Net gain (loss) from foreign currency translation | 44,211 | (35,864) | 30,788 | 107,239 |
| Minimum pension liability adjustment | — | — | — | (707) |
| **COMPREHENSIVE INCOME** | $ 159,408 | 42,767 | 592,991 | 354,944 |

See Notes to Consolidated Financial Statements, page 5.

Murphy Oil Corporation and Consolidated Subsidiaries

**CONSOLIDATED STATEMENTS OF CASH FLOWS (unaudited)**

(Thousands of dollars)

| | Nine Months Ended September 30, 2004 | Nine Months Ended September 30, 2003* |
|---|---|---|
| **OPERATING ACTIVITIES** | | |
| Income from continuing operations | $ 364,604 | 221,999 |
| Adjustments to reconcile income from continuing operations to net cash provided by operating activities | | |
| Depreciation, depletion and amortization | 238,504 | 183,949 |
| Provisions for major repairs | 22,692 | 20,687 |
| Expenditures for major repairs and asset retirement obligations | (14,700) | (60,558) |
| Dry hole costs | 100,370 | 48,282 |
| Amortization of undeveloped leases | 11,705 | 10,927 |
| Impairment of long-lived assets | — | 3,488 |
| Accretion of asset retirement obligations | 7,549 | 7,325 |
| Deferred and noncurrent income taxes | 96,765 | (5,327) |
| Pretax gains from disposition of assets | (69,900) | (59,651) |
| Net decrease in operating working capital other than cash and cash equivalents | 59,071 | 43,039 |
| Other | (6,817) | 5,416 |
| Net cash provided by continuing operations | 809,843 | 419,576 |
| Net cash provided by discontinued operations | 60,800 | 123,712 |
| Net cash provided by operating activities | 870,643 | 543,288 |
| **INVESTING ACTIVITIES** | | |
| Property additions and dry holes | (731,138) | (656,702) |
| Proceeds from the sale of assets | 59,538 | 77,899 |
| Other – net | (453) | 260 |
| Investing activities of discontinued operations | | |
| Sales proceeds | 582,675 | — |
| Other | (9,619) | (48,500) |
| Net cash required by investing activities | (98,997) | (627,043) |
| **FINANCING ACTIVITIES** | | |
| Increase (decrease) in notes payable | (27,592) | 227,689 |
| Decrease in nonrecourse debt of a subsidiary | (36,970) | (30,699) |
| Proceeds from exercise of stock options and employee stock purchase plans | 2,178 | 2,879 |
| Cash dividends paid | (57,496) | (55,090) |
| Other | — | (72) |
| Net cash provided by (used in) financing activities | (119,880) | 144,707 |
| Effect of exchange rate changes on cash and cash equivalents | 50,938 | 11,202 |
| Net increase in cash and cash equivalents | 702,704 | 72,154 |
| Cash and cash equivalents at January 1 | 252,425 | 164,957 |
| Cash and cash equivalents at September 30 | $ 955,129 | 237,111 |
| **SUPPLEMENTAL DISCLOSURES OF CASH FLOW ACTIVITIES** | | |
| Cash income taxes paid, net of refunds | $ 115,813 | 40,114 |
| Interest paid, net of amounts capitalized | 15,679 | 749 |

* Reclassified to conform to 2004 presentation.

See Notes to Consolidated Financial Statements, page 5.

*NOTES TO CONSOLIDATED FINANCIAL STATEMENTS*

These notes are an integral part of the financial statements of Murphy Oil Corporation and Consolidated Subsidiaries (Murphy/the Company) on pages 1 through 4 of this Form 10-Q report.

**Note A – Interim Financial Statements**

The consolidated financial statements of the Company presented herein have not been audited by independent auditors, except for the Consolidated Balance Sheet at December 31, 2003. In the opinion of Murphy's management, the unaudited financial statements presented herein include all accruals necessary to present fairly the Company's financial position at September 30, 2004, and the results of operations and cash flows for the three-month and nine-month periods ended September 30, 2004 and 2003, in conformity with accounting principles generally accepted in the United States.

Financial statements and notes to consolidated financial statements included in this Form 10-Q report should be read in conjunction with the Company's 2003 Form 10-K report, as certain notes and other pertinent information have been abbreviated or omitted in this report. Financial results for the nine months ended September 30, 2004 are not necessarily indicative of future results.

**Note B – Discontinued Operations**

The Company sold most of its Western Canadian conventional oil and gas assets (sale properties) in the second quarter of 2004 for total proceeds of $582.7 million. The Company recorded a gain of $169.2 million, net of $25.2 million in income taxes, from sale of the properties. The Company expects to utilize the proceeds of the sales to fund operations in Malaysia and other areas and/or to repay debt under revolving credit agreements. At the time of sale, the sale properties produced about 20,000 barrels of oil equivalent per day and had total reserves of approximately 46 million barrels equivalent from heavy oil, light oil, and natural gas properties. The operating results from the sale properties have been reported as discontinued operations beginning in the first quarter of 2004. Operating results for the three-month and nine-month periods ended September 30, 2003 have been reclassified to conform to this presentation. These sale properties were formerly included in the Canadian exploration and production segment. The major assets (liabilities) associated with the sale properties were as follows:

| (Thousands of dollars) | |
|---|---|
| Inventory | $ 1,741 |
| Prepaid expense | 907 |
| Property, plant and equipment, net of accumulated depreciation, depletion and amortization | 408,119 |
| Goodwill, net | 23,091 |
| Other noncurrent assets | 4,214 |
| Assets sold | $438,072 |
| Deferred income taxes | $ (25,125) |
| Asset retirement obligations | (49,969) |
| Liabilities associated with assets sold | $ (75,094) |

The following table reflects the results of operations from the sale properties including the 2004 gain on sale.

| | Three Months Ended September 30, | | Nine Months Ended September 30, | |
|---|---|---|---|---|
| (Thousands of dollars) | 2004 | 2003 | 2004 | 2003 |
| Revenues, including a pretax gain on sale of assets of $194,440 in the nine month period ended September 30, 2004 | $ 4,638 | 47,202 | 274,610 | 165,533 |
| Income before income tax expense | 5,490 | 5,251 | 243,572 | 45,273 |
| Income tax expense | 2,540 | 3,301 | 41,341 | 24,744 |

**Note C – Employee and Retiree Pension and Postretirement Plans**

The Company has defined benefit pension plans that are principally noncontributory and cover most full-time employees. All pension plans are funded except for the U.S. and Canadian nonqualified supplemental plans and the U.S. directors' plan. All U.S. tax qualified plans meet the funding requirements of federal laws and regulations.

Contributions to foreign plans are based on local laws and tax regulations. The Company also sponsors health care and life insurance benefit plans, which are not funded, that cover most retired U.S. employees. The health care benefits are contributory; the life insurance benefits are noncontributory.

The table that follows provides the components of net periodic benefit expense for the three-month and nine-month periods ended September 30, 2004 and 2003.

| | Three Months Ended September 30, | | | |
|---|---|---|---|---|
| | 2004 | 2003 | 2004 | 2003 |
| (Thousands of dollars) | Pension Benefits | | Postretirement Benefits | |
| Service cost | $ 1,916 | 2,015 | 316 | 310 |
| Interest cost | 4,774 | 4,906 | 856 | 925 |
| Expected return on plan assets | (4,705) | (4,587) | — | — |
| Amortization of prior service cost | (50) | (456) | (180) | (24) |
| Amortization of transitional asset | 100 | 95 | — | — |
| Recognized actuarial loss | 1,198 | 985 | 455 | 335 |
| | 3,233 | 2,958 | 1,447 | 1,546 |
| Settlement gain | (507) | — | — | — |
| Net periodic benefit expense | $ 2,726 | 2,958 | 1,447 | 1,546 |

| | Nine Months Ended September 30, | | | |
|---|---|---|---|---|
| | 2004 | 2003 | 2004 | 2003 |
| (Thousands of dollars) | Pension Benefits | | Postretirement Benefits | |
| Service cost | $ 6,593 | 6,445 | 994 | 946 |
| Interest cost | 14,663 | 15,928 | 2,694 | 2,824 |
| Expected return on plan assets | (14,197) | (15,010) | — | — |
| Amortization of prior service cost | (189) | (1,525) | (566) | (73) |
| Amortization of transitional asset | 303 | 370 | — | — |
| Recognized actuarial loss | 3,338 | 3,177 | 1,433 | 1,022 |
| | 10,511 | 9,385 | 4,555 | 4,719 |
| Settlement gain | (1,041) | — | — | — |
| Net periodic benefit expense | $ 9,470 | 9,385 | 4,555 | 4,719 |

Murphy previously disclosed in its financial statements for the year ended December 31, 2003, that it expected to contribute $3.6 million to its domestic defined benefit pension plans and $4.6 million to its postretirement benefits plan during 2004. As of September 30, 2004, $2.9 million, $1.8 million and $1.1 million of contributions have been made to the domestic defined benefit pension plans, postretirement benefits plan and foreign defined benefit plans, respectively. Murphy presently anticipates contributing during the last three months of 2004 an additional $1.4 million in the aggregate to fund its domestic plans. Murphy also anticipates contributing $.4 million in the last three months of 2004 to fund its existing foreign defined benefit pension plans. Total anticipated funding in 2004 for the Company's domestic and foreign defined benefits pension and postretirement benefits plans is $7.6 million.

On December 8, 2003, the President signed the Medicare Prescription Drug, Improvement and Modernization Act of 2003 (the Act). Among other provisions, the Act will provide prescription drug coverage under Medicare beginning in 2006. Generally, companies that provide qualifying prescription drug coverage that is deemed actuarially equivalent to medicare coverage for retirees aged 65 and above will be eligible to receive a federal subsidy equal to 28% of drug costs between $250 and $5,000 per annum for each covered individual that does not elect to receive coverage under the new prescription drug Medicare Part D. The Company currently provides prescription drug coverage to qualifying retirees under its retiree medical plan. As a result of provisions in the Act, the Company's accumulated postretirement benefit obligation will be reduced by approximately $6.3 million and its postretirement benefit expense will be $1 million lower during 2004, with $.7 million of the reduction recognized in the nine months ended September 30, 2004.

**Note D – Financial Instruments and Risk Management**

Murphy utilizes derivative instruments to manage certain risks related to interest rates, commodity prices and foreign currency exchange rates. The use of derivative instruments for risk management is covered by operating policies and is closely monitored by the Company's senior management. The Company does not hold any derivatives for speculative purposes, and it does not use derivatives with leveraged or complex features. Derivative instruments are traded primarily with creditworthy major financial institutions or over national exchanges. To qualify for hedge accounting, the changes in the market value of a derivative instrument must historically have been, and would be expected to continue to be, highly effective at offsetting changes in the prices of the hedged item. To the extent that the change in fair value of a derivative instrument has less than perfect correlation with the change in the fair value of the hedged item, a portion of the change in fair value of the derivative instrument is considered ineffective and would normally be recorded in earnings during the affected period.

- *Interest Rate Risks* – Murphy has variable-rate debt obligations that expose the Company to the effects of changes in interest rates. To partially reduce its exposure to interest rate risk, Murphy had interest rate swap agreements with notional amounts totaling $15 million at September 30, 2004 to hedge fluctuations in cash flows of a similar amount of variable rate debt. The swaps mature in October 2004. Under the interest rate swaps, the Company pays fixed rates averaging 5.98% over their composite lives and receives variable rates which averaged 1.68% at September 30, 2004. The variable rate received by the Company under each contract is repriced quarterly. The Company has a risk management control system to monitor interest rate cash flow risk attributable to the Company's outstanding and forecasted debt obligations as well as the offsetting interest rate swaps. The control system involves using analytical techniques, including cash flow sensitivity analysis, to estimate the impact of interest rate changes on future cash flows. The fair value of the effective portions of the interest rate swaps and changes thereto is deferred in Accumulated Other Comprehensive Income (AOCI) and is subsequently reclassified into Interest Expense in the periods in which the hedged interest payments on the variable-rate debt affect earnings. For the periods ended September 30, 2004 and 2003, the income effect from cash flow hedging ineffectiveness of interest rates was insignificant. The fair value of the interest rate swaps is estimated using projected Federal funds rates, Canadian overnight funding rates and LIBOR forward curve rates obtained from published indices and counterparties. The estimated fair value approximates the values based on quotes from each of the counterparties.
- *Natural Gas Fuel Price Risks* – The Company purchases natural gas as fuel at its Meraux, Louisiana and Superior, Wisconsin refineries, and as such, is subject to commodity price risk related to the purchase price of this gas. Murphy has hedged the cash flow risk associated with the cost of a portion of the natural gas it will purchase in 2004 through 2006 by entering into financial contracts known as natural gas swaps with a remaining notional volume as of September 30, 2004 of 3.9 million MMBTU (1 MMBTU = 1 million British Thermal Units). Under the natural gas swaps, the Company pays a fixed rate averaging $2.78 per MMBTU and receives a floating rate in each month of settlement based on the average NYMEX price for the final three trading days of the month. Murphy has a risk management control system to monitor natural gas price risk attributable both to forecasted natural gas requirements and to Murphy's natural gas swaps. The control system involves using analytical techniques, including various correlations of natural gas purchase prices to future prices, to estimate the impact of changes in natural gas fuel prices on Murphy's cash flows. The fair value of the effective portions of the natural gas swaps and changes thereto is deferred in AOCI and is subsequently reclassified into Operating Expenses in the income statements in the periods in which the hedged natural gas fuel purchases affect earnings. During 2003, the Company determined that natural gas swap contract notional volumes exceeded forecasted 2004 natural gas purchases at its Meraux, Louisiana refinery while the ROSE unit is out of service. Accordingly, natural gas swap contracts with a notional volume of 1 million MMBTU no longer qualified as a cash flow hedge. Therefore, .4 million MMBTU of these contracts were redesignated as a cash flow hedge of natural gas the Company will purchase at its Superior refinery during 2004, and the remaining .6 million MMBTU not qualifying as a hedge have been marked to fair value through earnings during 2004. During the first quarter 2004 the Company entered into 2.5 million MMBTU in natural gas price swap agreements that effectively fixed the settlement price of the contracts maturing in July through October 2004. The critical terms of all the 2004 contracts are nearly identical. Murphy is required to pay the average NYMEX price for the final three trading days of the month and receive an average natural gas price of $5.235 per MMBTU. The natural gas swap contracts designated as hedges of natural gas the Company will purchase in 2005 through 2006 at the Meraux refinery still qualify as cash flow hedges. For the period ended September 30, 2004, the income effect from cash flow hedging ineffectiveness for these contracts was $.4 million, net of $.2 million in income taxes. For the period ended September 30, 2003, the income effect from ineffectiveness was insignificant. During the nine-month period ended September 30, 2004, the Company received approximately $14.5 million for maturing swap agreements.

**Note D – Financial Instruments and Risk Management (Contd.)**

- *Natural Gas Sales Price Risks* – The sales price of natural gas produced by the Company is subject to commodity price risk. During the first quarter of 2004 Murphy entered into natural gas put options covering a combined United States natural gas sales volume averaging 25,000 MMBTU per day. The strike price provides the Company with a floor price of $4.00 per MMBTU and settles monthly through October 2004. During 2003 Murphy hedged the cash flow risk associated with the sales price for a portion of the natural gas it produced in the United States and Canada by entering into financial contracts known as natural gas swaps and collars. The swaps covered a combined notional volume averaging 24,200 MMBTU equivalents per day and required Murphy to pay the average relevant index (NYMEX or AECO "C") price for each month and receive an average price of $3.76 per MMBTU equivalent. The natural gas collars were for a combined notional volume averaging 26,700 MMBTU equivalents per day and based upon the relevant index prices provided Murphy with an average floor price of $3.24 per MMBTU and an average ceiling price of $4.64 per MMBTU. Murphy has a risk management control system to monitor natural gas price risk attributable both to forecasted natural gas sales prices and to Murphy's hedging instruments. The control system involves using analytical techniques, including various correlations of natural gas sales prices to futures prices, to estimate the impact of changes in natural gas prices on Murphy's cash flows from the sale of natural gas.

  The fair values of the effective portions of the natural gas swaps, collars and puts and changes thereto are deferred in AOCI and are subsequently reclassified into Sales and Other Operating Revenues in the income statement in the periods in which the hedged natural gas sales affect earnings. For the nine-month periods ended September 30, 2004 and 2003, Murphy's earnings were not significantly affected by cash flow hedging ineffectiveness.

  There were no settlement payments received in the 2004 period relating to the natural gas put options. During the nine-month period ended September 30, 2003, the Company paid $12.8 million for settlement of natural gas swap and collar agreements in the U.S. and Canada.

  The fair value of the natural gas fuel swaps and the natural gas sales swaps and collars are both based on the average fixed price of the instruments and the published NYMEX and AECO "C" index futures price or natural gas price quotes from counterparties.

- *Crude Oil Sales Price Risks* – The sales price of crude oil produced by the Company is subject to commodity price risk. During the third quarter of 2004 Murphy hedged the cash flow risk associated with the sales price for a portion of its Canadian heavy oil production during 2005 and 2006 by entering into forward sale contracts covering a notional volume of approximately 2,000 barrels per day for each of the periods. The Company will pay the average of the posted price at the Hardisty terminal in Canada for each month and receive a fixed price of $29.00 per barrel in 2005 and $24.70 per barrel in 2006. Murphy hedged the cash flow risk associated with the sales price for a portion of the crude oil it produced in the United States and Canada during 2003 by entering into financial contracts known as crude oil swaps. A portion of the swaps covered a notional volume of 22,000 barrels per day of light oil and required Murphy to pay the average of the closing settlement price on the NYMEX for the Nearby Light Crude Futures Contract for each month and receive an average price of $25.30 per barrel. Additionally, there were heavy oil swaps with a notional volume of 10,000 barrels per day (which equated to approximately 7,700 barrels per day of the Company's heavy oil production) that required Murphy to pay the arithmetic average of the posted price at the Kerrobert and Hardisty terminals in Canada for each month and receive an average price of $16.74 per barrel. Murphy has a risk management control system to monitor crude oil price risk attributable both to forecasted crude oil sales prices and to Murphy's hedging instruments. The control system involves using analytical techniques, including various correlations of crude oil sales prices to futures prices, to estimate the impact of changes in crude oil prices on Murphy's cash flows from the sale of light and heavy crude oil.

  The fair values of the effective portions of the crude oil hedges and changes thereto are deferred in AOCI and subsequently reclassified into Sales and Other Operating Revenues in the income statement in the periods in which the hedged crude oil sales affected earnings. In the nine-months of 2004, cash flow hedging ineffectiveness relating to the crude oil sales contracts decreased Murphy's after-tax earnings by $.5 million. In the nine-months of 2003, cash flow hedging ineffectiveness relating to the crude oil sales swaps increased Murphy's after-tax earnings by $.6 million.

**Note D – Financial Instruments and Risk Management (Contd.)**

During the nine-month period ended September 30, 2003, the Company paid $51.3 million for settlement of maturing crude oil swaps.

The fair value of the crude oil sales swaps is based on the average fixed price of the instruments and the published NYMEX index futures price or crude oil price quotes from counterparties.

During the next 12 months, the Company expects to reclassify approximately $5.8 million in net after-tax gains from AOCI into earnings as the forecasted transactions covered by hedging instruments actually occur. All forecasted transactions currently being hedged are expected to occur by December 2006.

**Note E – Asset Retirement Obligations**

On January 1, 2003, the Company adopted Statement of Financial Accounting Standards No. 143, Accounting for Asset Retirement Obligations, which requires the Company to record a liability equal to the fair value of the estimated cost to retire an asset. The asset retirement liability is recorded in the period in which the obligation meets the definition of a liability, which is generally when the asset is placed in service. When the liability is initially recorded, the Company will increase the carrying amount of the related long-lived asset by an amount equal to the original liability. The liability is accreted to its present value each period, and the capitalized cost is depreciated over the useful life of the related long-lived asset. Any difference between costs incurred upon settlement of an asset retirement obligation and the recorded liability is recognized as a gain or loss in the Company's earnings.

The estimation of the future asset retirement obligation is based on a number of assumptions requiring professional judgment. The Company cannot predict the type of revisions to these assumptions that will be required in future periods due to the availability of additional information such as prices for oil field services, technological changes, governmental requirements and other factors. Upon adoption of SFAS No. 143, the Company recorded a charge of $7 million, net of $1.4 million in income taxes, as the cumulative effect of a change in accounting principle. The noncash transition adjustment increased property, plant and equipment, accumulated depreciation, and asset retirement obligations by $142.9 million, $58.8 million, and $92.5 million, respectively.

The majority of the asset retirement obligation (ARO) recognized by the Company at September 30, 2004 relates to the estimated costs to dismantle and abandon its producing oil and gas properties and related equipment. A portion of the transition adjustment and ARO relates to retail gasoline stations. The Company did not record a retirement obligation for certain of its refining and marketing assets because sufficient information is presently not available to estimate a range of potential settlement dates for the obligation. In these cases, the obligation will be initially recognized in the period in which sufficient information exists to estimate the obligation.

A reconciliation of the beginning and ending aggregate carrying amount of the asset retirement obligations is shown in the following table.

| (Thousands of dollars) | 2004 | 2003 |
|---|---|---|
| Balance at January 1 | $252,397 | 160,543 |
| Transition adjustment | — | 92,500 |
| Accretion expense | 8,757 | 9,326 |
| Liabilities incurred | 17,491 | 17,582 |
| Liabilities settled | (85,669) | (58,536) |
| Revisions of previous estimates | (5,393) | — |
| Changes due to translation of foreign currencies | (2,140) | 17,225 |
| Balance at September 30 | $185,443 | 238,640 |

Accretion expense of $1.2 million and $2 million shown in the above table were included in discontinued operating results for the nine months ended September 30, 2004 and 2003, respectively. Liabilities settled in 2004 and 2003 included approximately $77.2 million and $54.9 million, respectively, in noncash reductions of asset retirement obligations associated with the sale of oil and gas properties.

**Note F – Earnings per Share and Stock Options**

Net income was used as the numerator in computing both basic and diluted income per Common share for the three-month and nine-month periods ended September 30, 2004 and 2003. The following table reconciles the weighted-average shares outstanding used for these computations.

| | Three Months Ended September 30, | | Nine Months Ended September 30, | |
|---|---|---|---|---|
| | 2004 | 2003 | 2004 | 2003 |
| (Weighted-average shares) | | | | |
| Basic method | 92,005,813 | 91,850,217 | 91,972,427 | 91,799,551 |
| Dilutive stock options | 1,562,608 | 998,091 | 1,393,120 | 813,360 |
| Diluted method | 93,568,421 | 92,848,308 | 93,365,547 | 92,612,911 |

There were no antidilutive options for the three-month and nine-month periods ended September 30, 2004 and 2003.

The Company accounts for its stock options using the intrinsic-value based method of accounting as prescribed by Accounting Principles Board (APB) Opinion No. 25, Accounting for Stock Issued to Employees, and related interpretations. Under this method, compensation expense is not recorded for stock options since all option prices have been equal to or greater than the fair market value of the Company's stock on the date of grant. The Company would record compensation expense for any stock options deemed to be variable in nature. The Company accrues compensation expense for restricted stock awards and adjusts such costs for changes in the fair market value of Common Stock. SFAS No. 123, Accounting for Stock-Based Compensation, established accounting and disclosure requirements using a fair-value based method for stock-based employee compensation plans. As allowed by SFAS No. 123, the Company has elected to continue to apply the intrinsic-value based method prescribed by APB No. 25 and has adopted only the disclosure requirements of SFAS No. 123. Had the Company recorded compensation expense for stock options using SFAS No. 123, net income and earnings per share for the three-month and nine-month periods ended September 30, 2004 and 2003 would be the pro forma amounts shown in the table below.

| | Three Months Ended September 30, | | Nine Months Ended September 30, | |
|---|---|---|---|---|
| **(Thousands of dollars except per share data)** | 2004 | 2003 | 2004 | 2003 |
| Net income – As reported | $118,723 | 68,737 | 566,835 | 235,535 |
| Restricted stock compensation expense included in income, net of tax | 382 | — | 893 | 197 |
| Total stock-based compensation expense using fair value method for all awards, net of tax | (1,602) | (1,388) | (4,623) | (4,016) |
| Net income – Pro forma | $117,503 | 67,349 | 563,105 | 231,716 |
| Net income per share – As reported, basic | $ 1.29 | .75 | 6.16 | 2.56 |
| Pro forma, basic | 1.28 | .73 | 6.12 | 2.52 |
| As reported, diluted | 1.27 | .74 | 6.07 | 2.54 |
| Pro forma, diluted | 1.26 | .72 | 6.03 | 2.50 |

The FASB has issued a proposed statement that would amend SFAS No. 123 to require the Company to record in earnings the portion of stock-based compensation cost related to awards granted or modified after December 15, 1994 that is not vested at the time of adoption of the new standard. The proposed statement would be effective for periods beginning after June 15, 2005.

**Note G – Accumulated Other Comprehensive Income**

The components of Accumulated Other Comprehensive Income on the Consolidated Balance Sheets at September 30, 2004 and December 31, 2003 are presented in the following table.

| (Thousands of dollars) | September 30, 2004 | December 31, 2003 |
|---|---|---|
| Foreign currency translation gain | $ 119,377 | 88,589 |
| Cash flow hedging, net | 4,826 | 9,458 |
| Minimum pension liability, net | (32,801) | (32,801) |
| Accumulated other comprehensive income | $ 91,402 | 65,246 |

The 2004 nine-month statement of income included after-tax foreign exchange losses of $7.8 million, while the nine-month 2003 statement of income included after-tax foreign exchange gains of $5.4 million.

The effect of SFAS Nos. 133/138, Accounting for Derivative Instruments and Hedging Activities, decreased AOCI for the three months ended September 30, 2004 by $3.5 million, net of $1.6 million in income taxes, and hedging ineffectiveness decreased net income by $.3 million, net of $.1 million in income taxes. During the nine-month period ended September 30, 2004, hedging activities decreased AOCI by $4.6 million, net of $2.2 million in income taxes, and hedging ineffectiveness decreased net income by less than $.1 million. Gains of $8.6 million, net of $4.6 million in taxes, were reclassified from AOCI to earnings in the nine-month period ended September 30, 2004. During the three-month period ended September 30, 2003, AOCI increased by $9.9 million, net of $6.8 million in income taxes, and hedging ineffectiveness decreased net income by $.8 million, net of $.4 million in income taxes. During the nine months of 2003, hedging activities increased AOCI by $12.9 million, net of $8 million in income taxes, and hedging ineffectiveness increased net income by $.6 million, net of $.4 million in income taxes. For the nine months ended September 30, 2003, losses of $38 million, net of $26.8 million in taxes, were reclassified from AOCI to earnings.

**Note H – Environmental Contingencies**

In addition to being subject to numerous laws and regulations intended to protect the environment and/or impose remedial obligations, the Company is also involved in personal injury and property damage claims, allegedly caused by exposure to or by the release or disposal of materials manufactured or used in the Company's operations. The Company operates or has previously operated certain sites and facilities, including three refineries, five terminals, and approximately 82 service stations for which known or potential obligations for environmental remediation exist. In addition the Company operates or has operated numerous oil and gas fields that may require some form of remediation, which is generally provided for by the Company's asset retirement obligation.

The Company's liability for remedial obligations includes certain amounts that are based on anticipated regulatory approval for proposed remediation of former refinery waste sites. If regulatory authorities require more costly alternatives than the proposed processes, future expenditures could exceed the accrued liability by up to an estimated $3 million.

The U.S. Environmental Protection Agency (EPA) currently considers the Company a Potentially Responsible Party (PRP) at two Superfund sites. The potential total cost to all parties to perform necessary remedial work at these sites may be substantial. Based on currently available information, the Company believes that it is a de minimus party as to ultimate responsibility at both Superfund sites. The Company could be required to bear a pro rata share of costs attributable to nonparticipating PRPs or could be assigned additional responsibility for remediation at the two sites or other Superfund sites. The Company does not believe that the ultimate costs to clean-up the two Superfund sites will have a material adverse effect on its net income or cash flows in a future period.

There is the possibility that environmental expenditures could be required at currently unidentified sites, and new or revised regulations could require additional expenditures at known sites. However, based on information currently available to the Company, the amount of future remediation costs incurred at known or currently unidentified sites is not expected to have a material adverse effect on future net income or cash flows.

**Note I – Other Contingencies**

The Company's operations and earnings have been and may be affected by various forms of governmental action both in the United States and throughout the world. Examples of such governmental action include, but are by no means limited to: tax increases and retroactive tax claims; import and export controls; price controls; currency controls; allocation of supplies of crude oil and petroleum products and other goods; expropriation of property; restrictions and preferences affecting the issuance of oil and gas or mineral leases; restrictions on drilling and/or production; laws and regulations intended for the promotion of safety and the protection and/or remediation of the environment; governmental support for other forms of energy; and laws and regulations affecting the Company's relationships with employees, suppliers, customers, stockholders and others. Because governmental actions are often motivated by political considerations and may be taken without full consideration of their consequences or in response to actions of other governments, it is not practical to attempt to predict the likelihood of such actions, the form the actions may take or the effect such actions may have on the Company.

In December 2000, two of the Company's Canadian subsidiaries, Murphy Oil Company Ltd. (MOCL) and Murphy Canada Exploration Company (MCEC) as plaintiffs filed an action in the Court of Queen's Bench of Alberta seeking a constructive trust over oil and gas leasehold rights to Crown lands in British Columbia. The suit alleges that the defendants, the Predator Corporation Ltd. and Predator Energies Partnership (collectively Predator) and Ricks Nova Scotia Co. (Ricks), acquired the lands after first inappropriately obtaining confidential and proprietary data belonging to the Company and its partner. In January 2001, Ricks, representing an undivided 75% interest in the lands in question, settled its portion of the litigation by conveying its interest to the Company and its partner at cost. In 2001, Predator, representing the remaining undivided 25% of the lands in question, filed a counterclaim, as subsequently amended, against MOCL and MCEC and MOCL's president individually seeking compensatory damages of C$3.61 billion. In September 2004 the court summarily dismissed all claims against MOCL's president and all but C$356 million of the counterclaim against the Company; however, this dismissal order is currently on appeal. It is anticipated that a trial concerning the 25% disputed interest and any remaining issues will commence in 2005. While the litigation is in the discovery stage and no assurance can be given about the outcome, the Company does not believe that the ultimate resolution of this suit will have a material adverse effect on its financial condition or its results of operations.

On June 10, 2003, a fire severely damaged the Residual Oil Supercritical Extraction (ROSE) unit at the Company's Meraux, Louisiana refinery. The ROSE unit recovers feedstock from the heavy fuel oil stream for conversion into gasoline and diesel. Subsequent to the fire, numerous class action lawsuits have been filed seeking damages for area residents. All the lawsuits have been administratively consolidated into a single legal action in St. Bernard Parish, Louisiana, except for one such action which was filed in federal court. Additionally, individual residents of Orleans Parish, Louisiana, have filed an action in that venue. On May 5, 2004, plaintiffs in the consolidated action in St. Bernard Parish amended their petition to include a direct action against certain of the Company's liability insurers. In responding to this direct action, one of the Company's insurers, AEGIS, has raised lack of coverage as a defense. The Company believes that this contention lacks merit and has been advised by counsel that the applicable policy does provide coverage for the underlying incident. The Company continues to believe that the ultimate resolution of the June 2003 ROSE fire litigation will not have a material adverse effect on its financial condition.

On March 5, 2002, two of the Company's subsidiaries filed suit against Enron Canada Corp. (Enron) to collect approximately $2.1 million owed to Murphy under canceled gas sales contracts. On May 1, 2002, Enron counterclaimed for approximately $19.8 million allegedly owed by Murphy under those same agreements. Although the lawsuit in the Court of Queen's Bench, Alberta, is in its early stages and no assurance can be given about the outcome, the Company does not believe that the Enron counterclaim is meritorious and does not believe that the ultimate resolution of this matter will have a material adverse effect on its financial condition.

Murphy and its subsidiaries are engaged in a number of other legal proceedings, all of which Murphy considers routine and incidental to its business and none of which is expected to have a material adverse effect on the Company's financial condition. Based on information currently available to the Company, the ultimate resolution of environmental and legal matters referred to in this note is not expected to have a material adverse effect on the Company's earnings or financial condition in a future period.

In the normal course of its business, the Company is required under certain contracts with various governmental authorities and others to provide financial guarantees or letters of credit that may be drawn upon if the Company fails to perform under those contracts. At September 30, 2004, the Company had contingent liabilities of $9 million under a financial guarantee and $51.8 million on outstanding letters of credit. The Company has not accrued a liability in its balance sheet related to these letters of credit because it is believed that the likelihood of having these drawn is remote.

**Note J – Accounting Matters**

In July 2003 the FASB undertook to review whether mineral interests in properties (mineral leases) held by oil and gas companies should be recorded and disclosed as intangible assets under the guidance of SFAS No. 141, Business Combinations, and SFAS No. 142, Goodwill and Other Intangible Assets. After consideration of the matter, the FASB issued a staff position stating that drilling and mineral rights of oil and gas producing entities that are within the scope of SFAS 19 are not subject to the intangible asset classification and disclosure rules of SFAS No. 142. The staff position is consistent with the Company's present accounting practices and had no effect on its financial statements or disclosures.

**Note K – Business Segments**

| | | Three Months Ended September 30, 2004 | | | Three Months Ended September 30, 2003 | | |
|---|---|---|---|---|---|---|---|
| (Millions of dollars) | Total Assets at Sept. 30, 2004 | External Revenues | Inter-segment Revenues | Income (Loss) | External Revenues | Inter-segment Revenues | Income (Loss) |
| Exploration and production* | | | | | | | |
| United States | $ 819.7 | 104.4 | — | 33.0 | 45.3 | — | (.2) |
| Canada | 1,275.9 | 136.3 | 17.8 | 52.8 | 108.0 | 15.4 | 43.0 |
| United Kingdom | 199.4 | 81.0 | — | 42.8 | 27.5 | — | 10.0 |
| Ecuador | 112.7 | .4 | — | (.1) | 9.5 | — | 3.7 |
| Malaysia | 437.9 | 53.4 | — | (7.0) | 40.7 | — | 10.9 |
| Other | 21.9 | .9 | — | (2.9) | .5 | — | (1.8) |
| Total | 2,867.5 | 376.4 | 17.8 | 118.6 | 231.5 | 15.4 | 65.6 |
| Refining and marketing | | | | | | | |
| North America | 1,398.8 | 1,752.1 | — | 12.9 | 910.7 | — | 3.8 |
| United Kingdom | 323.0 | 172.9 | — | 5.8 | 119.6 | — | 1.1 |
| Total | 1,721.8 | 1,925.0 | — | 18.7 | 1,030.3 | — | 4.9 |
| Total operating segments | 4,589.3 | 2,301.4 | 17.8 | 137.3 | 1,261.8 | 15.4 | 70.5 |
| Corporate | 1,012.9 | (7.9) | — | (21.5) | 1.2 | — | (3.7) |
| Total from continuing operations | 5,602.2 | 2,293.5 | 17.8 | 115.8 | 1,263.0 | 15.4 | 66.8 |
| Discontinued operations | — | — | — | 2.9 | — | — | 1.9 |
| Total | $ 5,602.2 | 2,293.5 | 17.8 | 118.7 | 1,263.0 | 15.4 | 68.7 |

| | Nine Months Ended September 30, 2004 | | | Nine Months Ended September 30, 2003 | | |
|---|---|---|---|---|---|---|
| (Millions of dollars) | External Revenues | Inter-segment Revenues | Income (Loss) | External Revenues | Inter-segment Revenues | Income (Loss) |
| Exploration and production* | | | | | | |
| United States | $ 367.4 | — | 117.2 | 145.9 | — | 15.4 |
| Canada | 391.3 | 53.8 | 170.9 | 308.0 | 37.4 | 122.8 |
| United Kingdom | 161.1 | — | 72.4 | 177.1 | — | 76.5 |
| Ecuador | 30.5 | — | 6.6 | 25.6 | — | 10.0 |
| Malaysia | 122.9 | — | (.4) | 40.7 | — | .1 |
| Other | 2.5 | — | (7.1) | 2.8 | — | (3.2) |
| Total | 1,075.7 | 53.8 | 359.6 | 700.1 | 37.4 | 221.6 |
| Refining and marketing | | | | | | |
| North America | 4,504.0 | — | 29.8 | 2,686.4 | — | (4.1) |
| United Kingdom | 477.7 | — | 22.0 | 358.0 | — | 5.8 |
| Total | 4,981.7 | — | 51.8 | 3,044.4 | — | 1.7 |
| Total operating segments | 6,057.4 | 53.8 | 411.4 | 3,744.5 | 37.4 | 223.3 |
| Corporate | 1.5 | — | (46.8) | 3.4 | — | (1.3) |
| Total from continuing operations | 6,058.9 | 53.8 | 364.6 | 3,747.9 | 37.4 | 222.0 |
| Discontinued operations | — | — | 202.2 | — | — | 20.5 |
| Cumulative effect of change in accounting principle | — | — | — | — | — | (7.0) |
| Total | $6,058.9 | 53.8 | 566.8 | 3,747.9 | 37.4 | 235.5 |

* Additional details about results of oil and gas operations are presented in the tables on page 18.

## *ITEM 2. MANAGEMENT'S DISCUSSION AND ANALYSIS OF RESULTS OF OPERATIONS AND FINANCIAL CONDITION*

**Results of Operations**

*Third Quarter 2004 vs. Third Quarter 2003*

Murphy's net income in the third quarter of 2004 was $118.7 million, $1.27 per share, compared to net income of $68.7 million, $.74 per share, in the third quarter of 2003. Net income in the current period included income from discontinued operations of $2.9 million, $.03 per share, associated with the sale of most of its conventional oil and gas assets in Western Canada in the second quarter 2004. Income from discontinued operations in the third quarter of 2003 was $1.9 million, $.02 per share. Income from continuing operations in the 2004 third quarter was $115.8 million, $1.24 per share, compared to $66.8 million, $.72 per share, in the same period of 2003. The 2004 income from continuing operations includes a $24.6 million after-tax gain on sale of the "T" Block field in the U.K. North Sea.

The Company's income from continuing exploration and production operations was $118.6 million in the current quarter, an increase of $53 million from $65.6 million earned in the 2003 period. The earnings improvement in 2004 was primarily caused by higher oil and natural gas sales prices and a $24.6 million after-tax gain on sale of the "T" Block field in the U.K. North Sea. These favorable items were partially offset by lower natural gas sales volumes, higher exploration expenses and $2.6 million in uninsured costs to repair storm damages from Hurricane Ivan in the Gulf of Mexico. The 2003 third quarter included an $11.4 million income tax benefit in Malaysia and a $2.3 million after-tax charge for impairment of assets in the Gulf of Mexico. The Company's refining and marketing results generated a profit of $18.7 million in the most recent quarter compared to $4.9 million in the 2003 quarter. The improvement was due to significantly better margins in North America and the United Kingdom in the current quarter, and higher crude runs at the Meraux, Louisiana refinery in the 2004 period. During the third quarter of 2003, the Company's Meraux refinery was off-line most of the period for repair of fire damages and a planned turnaround. The after-tax costs of the corporate functions were $21.5 million in the 2004 quarter compared to $3.7 million in the 2003 quarter. Losses on foreign exchange increased net after-tax costs in the 2004 period by $8.2 million, while the 2003 period included foreign exchange gains of $5.4 million, net of taxes. Higher administrative expenses were the other primary reason for increased costs in 2004.

*Nine Months 2004 vs. Nine Months 2003*

For the nine months of 2004, net income totaled $566.8 million, $6.07 per share, compared to $235.5 million, $2.54 per share, for the nine months of 2003. Continuing operations earned $364.6 million, $3.90 per share, in 2004 and $222 million, $2.40 per share, in 2003. Income from discontinued operations was $202.2 million, $2.17 per share, in the nine months of 2004, while the same period in 2003 totaled $20.5 million, $.22 per share. Income from discontinued operations in 2004 includes an after-tax gain on asset sales of $169.2 million. The 2003 period included an after-tax cost of $7 million, $.08 per share, for the cumulative effect of a change in accounting principle attributable to adoption, as of January 1, 2003, of Statement of Financial Accounting Standards No. 143, Accounting for Asset Retirement Obligations.

The Company's exploration and production operations earned $359.6 million in the nine months of 2004 and $221.6 million in the same period of 2003. Higher oil and natural gas sales prices and sales volumes in 2004 were the primary reasons for improved earnings, but these were partially offset by increased exploration expenses mostly due to higher costs for dry holes offshore Eastern Canada and Malaysia. The refining and marketing operations generated earnings of $51.8 million in 2004 compared to $1.7 million in 2003. The improved current year result was based on better margins in both North American and U.K. businesses in 2004. The 2003 U.S. results were unfavorably affected by a fire and planned turnaround at the Meraux refinery. Corporate after-tax costs were $46.8 million in the nine months of 2004 compared to $1.3 million in the 2003 period. The 2004 period included after-tax foreign exchange losses of $7.8 million, while 2003 included net foreign exchange gains of $5.4 million. Higher net interest and administrative expenses were also components of the increased costs in the 2004 period. The 2003 period also included a benefit of $20.1 million on U.S. tax settlements.

**Results of Operations (Contd.)**

*Exploration and Production*

Results of continuing exploration and production operations are presented by geographic segment below.

| | Income (Loss) | | | |
|---|---|---|---|---|
| | Three Months Ended September 30, | | Nine Months Ended September 30, | |
| (Millions of dollars) | 2004 | 2003 | 2004 | 2003 |
| Exploration and production | | | | |
| United States | $ 33.0 | (.2) | 117.2 | 15.4 |
| Canada | 52.8 | 43.0 | 170.9 | 122.8 |
| United Kingdom | 42.8 | 10.0 | 72.4 | 76.5 |
| Ecuador | (.1) | 3.7 | 6.6 | 10.0 |
| Malaysia | (7.0) | 10.9 | (.4) | .1 |
| Other International | (2.9) | (1.8) | (7.1) | (3.2) |
| Total | $ 118.6 | 65.6 | 359.6 | 221.6 |

Exploration and production operations in the United States reported earnings of $33 million in the third quarter of 2004 compared to a net loss of $.2 million a year ago. This improvement was primarily due to higher oil and natural gas sales prices coupled with higher sales volumes due to start-up, in the fourth quarter of 2003, of the Medusa and Habanero fields in deepwater Gulf of Mexico. Production expenses and depreciation expense increased due to the higher crude oil and natural gas sales volumes. The 2004 period also included costs of $2.6 million related to repair of storm damages in the Gulf of Mexico. Exploration expenses were $4.5 million lower in the 2004 period primarily due to lower dry hole expense.

Continuing operations in Canada earned $52.8 million this quarter compared to $43 million a year ago. This increase is primarily the result of higher crude oil and natural gas sales prices partially offset by a decline in crude oil and natural gas sales volume and higher exploration expenses offshore Eastern Canada. Oil and gas liquids sales in Canada averaged 41,625 barrels per day in the 2004 quarter, a decrease of 12% from the prior year's third quarter, primarily because of lower offshore sales volumes due to timing of oil loadings and planned annual maintenance.

U.K. operations earned $42.8 million in the current quarter, up from $10 million in the prior year. The significant improvement in the current period was due to a $24.6 million gain on the sale of the "T" Block field in the U.K. North Sea coupled with higher crude oil and natural gas sales prices and slightly higher crude oil sales volumes, due to timing of oil loadings.

Ecuador operations incurred a loss of $.1 million in the third quarter 2004 compared to earnings of $3.7 million a year ago. The decline in earnings was due to no sales occurring from Block 16 in the 2004 third quarter due to a dispute with the operator involving the Company's new transportation and marketing arrangements. As of September 30, 2004, the Company was approximately 900,000 barrels underlifted from Block 16 and the underlift will continue to grow into the fourth quarter. The applicable agreement calls for balanced inventory positions at year-end. Although the Company expects to make up this underlift in future months, it can make no assurance about the timing of rebalancing Block 16 inventories.

Operations in Malaysia reported a net loss of $7 million in the just completed quarter compared to income of $10.9 million in the same period in 2003. The decreased earnings in the current period was primarily attributable to lower crude oil sales volumes at West Patricia field in Block SK 309 in shallow-water Malaysia and higher production and exploration expenses, partially offset by higher crude oil sales prices. Additionally, the 2003 period included an $11.4 million tax benefit related to certain prior year expenses.

Other international operations incurred a net loss of $2.9 million in the 2004 period compared to a loss of $1.8 million in the same period a year ago. Higher exploration expenses in the Republic of Congo and higher administrative expenses were the primary causes of the higher loss in the 2004 period.

Operations in the United States for the nine months ended September 30, 2004 produced income of $117.2 million compared to 2003 income of $15.4 million. The improvement was primarily due to higher crude oil and natural gas sales volumes and prices, partially offset by higher dry hole expenses. The higher sales volumes are the result of the start-up in the last quarter of 2003 of the Medusa and Habanero fields in the deepwater Gulf of Mexico. Also

**Results of Operations (Contd.)**

*Exploration and Production* (Contd.)

contributing to the improved results in 2004 were approximately $15.4 million in after-tax gains on disposal of several minor natural gas properties onshore United States.

In the nine months of 2004, continuing operations in Canada earned $170.9 million compared to $122.8 million a year ago. Higher crude oil and natural gas sales prices were partially offset by lower natural gas sales volumes and higher exploration expenses. Production expenses for synthetic oil operations increased $9.6 million in the current period primarily due to higher employee benefits, repairs and natural gas costs.

The Company completed the sale of most of its conventional oil and gas assets in Western Canada in the second quarter of 2004 for net cash proceeds of $582.7 million, which generated an after-tax gain in discontinued operations of $169.2 million. The operating results of those sold assets have also been reported as discontinued operations for all periods presented.

Income in the U.K. for the nine-month period ended September 30, 2004 was $72.4 million compared to $76.5 million a year ago. The decrease was due to a lower gain on sale of oil fields in 2004 compared to 2003, and lower sales volumes of crude oil and natural gas in the 2004 period, partially offset by higher sales prices in the current period.

For the nine months of 2004, earnings in Ecuador were $6.6 million compared to $10 million for the 2003 period. Higher crude oil sales volumes and prices in Ecuador in the 2004 period were more than offset by higher production, depreciation and income tax expenses.

Malaysia reported a loss of $.4 million in the nine months of 2004 compared to earnings of $.1 million a year ago. Higher crude oil sales volumes and prices in the 2004 period were more than offset by higher expenses for production, depreciation, exploration and income taxes. The 2003 period included an $11.4 million tax benefit related to certain prior year expenses.

Other international operations incurred a loss of $7.1 million in the 2004 period compared to a loss of $3.2 million in the same period last year. Lower gas storage revenue and higher exploration and administrative expenses were the primary reasons for the increased loss.

On a worldwide basis, the Company's worldwide crude oil and condensate sales prices averaged $40.12 per barrel in the third quarter 2004 compared to $25.53 in the 2003 period. Average crude oil and liquids production from continuing operations was 88,445 barrels per day in the third quarter of 2004 compared to 78,436 barrels per day in the 2003 quarter, with the net increase primarily attributable to production at the Medusa and Habanero fields in the deepwater Gulf of Mexico, both of which commenced production in the fourth quarter of 2003. Crude oil sales volumes averaged 81,927 barrels per day in the third quarter 2004 compared to 81,299 barrels per day in the 2003 period. No sales occurred from Block 16 in Ecuador in the 2004 third quarter due to a dispute with the operator involving the Company's transportation and marketing arrangements. North American natural gas sales prices averaged $6.00 per thousand cubic feet (MCF) in the most recent quarter compared to $4.93 per MCF in the same quarter of 2003. Total natural gas sales volumes from continuing operations averaged 99 million cubic feet per day in the third quarter 2004 compared to 106 million cubic feet per day in the third quarter of 2003. The decline in natural gas sales was primarily due to sale of natural gas properties in Western Canada in the second quarter 2004 and downtime for tropical storms in the Gulf of Mexico in the third quarter 2004. United States production in the third quarter 2004 was reduced by 3,600 barrels of oil per day and eight million cubic feet of natural gas per day due to downtime caused by Hurricane Ivan.

For the nine months of 2004, the Company's sales price for crude oil and condensate averaged $34.84 per barrel compared to $26.00 per barrel in 2003. Crude oil and condensate production from continuing operations in the nine months of 2004 averaged 93,632 barrels per day up from 74,244 barrels per day in 2003. The increase was primarily attributable to start-up of the Medusa and Habanero fields in late 2003 and a full nine months of production at the West Patricia field in Malaysia. Average sales prices for North American natural gas in the nine months of 2004 were $6.04 per MCF, up from $5.37 in 2003. Total natural gas sales volume from continuing operations were 115 million cubic feet per day in the 2004 period up from 111 million cubic feet per day in 2003.

The tables on pages 17 and 18 provide additional details of the results of exploration and production operations for the third quarter and nine months of each year.

*Exploration and Production* (Contd.)

Selected operating statistics for the three-month and nine-month periods ended September 30, 2004 and 2003 follow.

| | Three Months Ended September 30, | | Nine Months Ended September 30, | |
|---|---|---|---|---|
| | 2004 | 2003 | 2004 | 2003 |
| Net crude oil, condensate and gas liquids produced – barrels per day | 88,428 | 84,871 | 97,713 | 81,065 |
| Continuing operations | 88,445 | 78,436 | 93,632 | 74,244 |
| United States | 17,063 | 4,011 | 19,657 | 3,774 |
| Canada – light | 601 | 815 | 671 | 1,324 |
| – heavy | 4,663 | 5,188 | 4,567 | 4,392 |
| – offshore | 23,390 | 26,700 | 26,715 | 28,408 |
| – synthetic | 12,048 | 12,009 | 11,976 | 10,604 |
| United Kingdom | 10,784 | 11,636 | 11,560 | 15,624 |
| Ecuador | 7,808 | 5,365 | 7,781 | 3,950 |
| Malaysia | 12,088 | 12,712 | 10,705 | 6,168 |
| Discontinued operations | (17) | 6,435 | 4,081 | 6,821 |
| Net crude oil, condensate and gas liquids sold – barrels per day | 81,910 | 87,734 | 96,019 | 80,128 |
| Continuing operations | 81,927 | 81,299 | 91,938 | 73,307 |
| United States | 17,063 | 4,011 | 19,657 | 3,774 |
| Canada – light | 601 | 815 | 671 | 1,324 |
| – heavy | 4,663 | 5,188 | 4,567 | 4,392 |
| – offshore | 24,313 | 29,119 | 27,816 | 28,948 |
| – synthetic | 12,048 | 12,009 | 11,976 | 10,604 |
| United Kingdom | 10,475 | 9,372 | 11,667 | 14,885 |
| Ecuador | 147 | 4,823 | 4,502 | 4,001 |
| Malaysia | 12,617 | 15,962 | 11,082 | 5,379 |
| Discontinued operations | (17) | 6,435 | 4,081 | 6,821 |
| Net natural gas sold – thousands of cubic feet per day | 98,858 | 203,162 | 157,172 | 220,703 |
| Continuing operations | 98,919 | 106,055 | 115,307 | 111,224 |
| United States | 81,531 | 85,071 | 94,525 | 82,220 |
| Canada | 13,424 | 14,754 | 14,205 | 20,521 |
| United Kingdom | 3,964 | 6,230 | 6,577 | 8,483 |
| Discontinued operations | (61) | 97,107 | 41,865 | 109,479 |
| Total net hydrocarbons produced – equivalent barrels per day (1) | 104,904 | 118,731 | 123,908 | 117,849 |
| Total net hydrocarbons sold – equivalent barrels per day (1) | 98,386 | 121,594 | 122,214 | 116,912 |
| Total net hydrocarbons produced from continuing operations – equivalent barrels per day (1) | 104,932 | 96,112 | 112,850 | 92,781 |
| Total net hydrocarbons sold from continuing operations – equivalent barrels per day (1) | 98,414 | 98,975 | 111,156 | 91,844 |
| Weighted average sales prices Crude oil and condensate – dollars per barrel (2) | | | | |
| United States (4) | $ 37.70 | 23.88 | 34.21 | 24.43 |
| Canada (3) – light | 40.49 | 23.33 | 36.02 | 27.64 |
| – heavy (4) | 23.25 | 13.23 | 20.07 | 12.80 |
| – offshore (4) | 40.16 | 27.08 | 35.30 | 26.70 |
| – synthetic (4) | 41.83 | 23.95 | 37.99 | 25.33 |
| United Kingdom | 42.52 | 28.80 | 35.98 | 29.43 |
| Ecuador | 30.51 | 21.40 | 24.73 | 23.42 |
| Malaysia | 45.99 | 27.66 | 40.36 | 27.66 |
| Natural gas – dollars per thousand cubic feet | | | | |
| United States (2) (4) | $ 6.17 | 4.94 | 6.16 | 5.48 |
| Canada (3) (4) | 4.98 | 4.85 | 5.24 | 4.95 |
| United Kingdom (3) | 3.73 | 2.28 | 4.13 | 3.11 |

(1) Natural gas converted on an energy equivalent basis of 6:1.
(2) Includes intracompany transfers at market prices.
(3) U.S. dollar equivalent.
(4) Three-month and nine-month 2003 prices include the effects of the Company's 2003 hedging program.

***CONTINUING OIL AND GAS OPERATING RESULTS (unaudited)***

| (Millions of dollars) | United States | Canada | United King-dom | Ecuador | Malaysia | Other | Synthetic Oil – Canada | Total |
|---|---|---|---|---|---|---|---|---|
| **Three Months Ended September 30, 2004** | | | | | | | | |
| Oil and gas sales and other revenues | $104.4 | 107.8 | 81.0 | .4 | 53.4 | .9 | 46.3 | 394.2 |
| Production expenses | 17.7 | 9.0 | 4.1 | .3 | 7.1 | — | 17.9 | 56.1 |
| Costs to repair storm damages | 2.6 | — | — | — | — | — | — | 2.6 |
| Depreciation, depletion and amortization | 15.0 | 23.3 | 6.4 | .1 | 8.2 | .1 | 2.7 | 55.8 |
| Accretion of asset retirement obligations | .9 | .8 | .6 | — | — | .1 | .1 | 2.5 |
| Exploration expenses | | | | | | | | |
| Dry holes | 7.6 | 23.2 | — | — | 19.0 | — | — | 49.8 |
| Geological and geophysical | 1.8 | .5 | — | — | 12.1 | .5 | — | 14.9 |
| Other | .8 | .1 | .1 | — | .1 | .3 | — | 1.4 |
| | 10.2 | 23.8 | .1 | — | 31.2 | .8 | — | 66.1 |
| Undeveloped lease amortization | 3.0 | .7 | — | — | — | .4 | — | 4.1 |
| Total exploration expenses | 13.2 | 24.5 | .1 | — | 31.2 | 1.2 | — | 70.2 |
| Selling and general expenses | 4.1 | 2.3 | .9 | .2 | 1.1 | 2.2 | .2 | 11.0 |
| Income tax provisions (benefits) | 17.9 | 12.2 | 26.1 | (.1) | 12.8 | .2 | 8.3 | 77.4 |
| Results of operations (excluding corporate overhead and interest) | $ 33.0 | 35.7 | 42.8 | (.1) | (7.0) | (2.9) | 17.1 | 118.6 |
| **Three Months Ended September 30, 2003** | | | | | | | | |
| Oil and gas sales and other revenues | $ 45.3 | 96.7 | 27.5 | 9.5 | 40.7 | .5 | 26.7 | 246.9 |
| Production expenses | 10.7 | 9.9 | 3.6 | 3.7 | 5.1 | — | 16.5 | 49.5 |
| Depreciation, depletion and amortization | 8.8 | 23.7 | 5.2 | 1.9 | 9.8 | .1 | 2.4 | 51.9 |
| Impairment of long-lived assets | 3.0 | — | — | — | — | — | — | 3.0 |
| Accretion of asset retirement obligations | .8 | .6 | .6 | — | .1 | .1 | .1 | 2.3 |
| Exploration expenses | | | | | | | | |
| Dry holes | 12.8 | 3.0 | (.1) | — | 13.3 | — | — | 29.0 |
| Geological and geophysical | 1.2 | 4.1 | — | — | 5.2 | .4 | — | 10.9 |
| Other | .6 | — | — | — | — | .1 | — | .7 |
| | 14.6 | 7.1 | (.1) | — | 18.5 | .5 | — | 40.6 |
| Undeveloped lease amortization | 3.1 | .8 | .1 | — | — | — | — | 4.0 |
| Total exploration expenses | 17.7 | 7.9 | — | — | 18.5 | .5 | — | 44.6 |
| Selling and general expenses | 4.6 | 5.6 | .7 | .2 | .6 | 1.6 | .1 | 13.4 |
| Income tax provisions (benefits) | (.1) | 14.2 | 7.4 | — | (4.3) | — | (.6) | 16.6 |
| Results of operations (excluding corporate overhead and interest) | $ (.2) | 34.8 | 10.0 | 3.7 | 10.9 | (1.8) | 8.2 | 65.6 |
| **Nine Months Ended September 30, 2004** | | | | | | | | |
| Oil and gas sales and other revenues | $367.4 | 320.5 | 161.1 | 30.5 | 122.9 | 2.5 | 124.6 | 1,129.5 |
| Production expenses | 56.6 | 27.2 | 15.8 | 13.8 | 18.2 | — | 55.4 | 187.0 |
| Costs to repair storm damages | 2.6 | — | — | — | — | — | — | 2.6 |
| Depreciation, depletion and amortization | 51.0 | 72.6 | 21.9 | 5.2 | 21.6 | .1 | 8.0 | 180.4 |
| Accretion of asset retirement obligations | 2.7 | 2.1 | 2.0 | — | .1 | .3 | .3 | 7.5 |
| Exploration expenses | | | | | | | | |
| Dry holes | 40.7 | 23.1 | — | — | 36.5 | .1 | — | 100.4 |
| Geological and geophysical | 5.7 | 1.7 | — | — | 15.1 | 1.2 | — | 23.7 |
| Other | 4.0 | 1.7 | .4 | — | .1 | .5 | — | 6.7 |
| | 50.4 | 26.5 | .4 | — | 51.7 | 1.8 | — | 130.8 |
| Undeveloped lease amortization | 9.4 | 1.9 | — | — | — | .4 | — | 11.7 |
| Total exploration expenses | 59.8 | 28.4 | .4 | — | 51.7 | 2.2 | — | 142.5 |
| Selling and general expenses | 14.2 | 8.0 | 2.4 | .5 | 3.5 | 6.5 | .5 | 35.6 |
| Income tax provisions (benefits) | 63.3 | 54.1 | 46.2 | 4.4 | 28.2 | .5 | 17.6 | 214.3 |
| Results of operations (excluding corporate overhead and interest) | $117.2 | 128.1 | 72.4 | 6.6 | (.4) | (7.1) | 42.8 | 359.6 |
| **Nine Months Ended September 30, 2003** | | | | | | | | |
| Oil and gas sales and other revenues | $145.9 | 271.8 | 177.1 | 25.6 | 40.7 | 2.8 | 73.6 | 737.5 |
| Production expenses | 27.4 | 27.1 | 24.4 | 10.7 | 5.1 | — | 45.8 | 140.5 |
| Depreciation, depletion and amortization | 26.3 | 69.0 | 23.2 | 4.5 | 10.3 | .2 | 6.7 | 140.2 |
| Impairment of long-lived assets | 3.0 | — | — | — | — | — | — | 3.0 |
| Accretion of asset retirement obligations | 2.4 | 1.8 | 2.3 | — | .2 | .3 | .3 | 7.3 |

| | | | | | | | | |
|---|---|---|---|---|---|---|---|---|
| Exploration expenses | | | | | | | | |
| Dry holes | 32.2 | 3.0 | (.1) | — | 13.3 | (.1) | — | 48.3 |
| Geological and geophysical | 7.0 | 4.3 | – | — | 12.7 | .4 | — | 24.4 |
| Other | 2.9 | .4 | .4 | — | .5 | .2 | — | 4.4 |
| | 42.1 | 7.7 | .3 | — | 26.5 | .5 | — | 77.1 |
| Undeveloped lease amortization | 8.5 | 2.4 | .1 | — | — | — | — | 11.0 |
| Total exploration expenses | 50.6 | 10.1 | .4 | — | 26.5 | .5 | — | 88.1 |
| Selling and general expenses | 12.5 | 10.5 | 2.3 | .4 | 2.8 | 4.8 | .4 | 33.7 |
| Income tax provisions (benefits) | 8.3 | 47.3 | 48.0 | — | (4.3) | .2 | 3.6 | 103.1 |
| Results of operations (excluding corporate overhead and interest) | $ 15.4 | 106.0 | 76.5 | 10.0 | .1 | (3.2) | 16.8 | 221.6 |

**Results of Operations (Contd.)**

*Refining and Marketing*

Results of refining and marketing operations are presented below by geographic segment.

| | Income (Loss) | | | |
|---|---|---|---|---|
| | Three Months Ended September 30, | | Nine Months Ended September 30, | |
| (Millions of dollars) | 2004 | 2003 | 2004 | 2003 |
| Refining and marketing | | | | |
| North America | $ 12.9 | 3.8 | 29.8 | (4.1) |
| United Kingdom | 5.8 | 1.1 | 22.0 | 5.8 |
| Total | $ 18.7 | 4.9 | 51.8 | 1.7 |

Refining and marketing operations in North America reported earnings of $12.9 million during the third quarter of 2004 compared to $3.8 million in the same period a year ago. Earnings in the United Kingdom were $5.8 million in the third quarter of 2004 compared to earnings of $1.1 million in 2003. Both operating segment's refining and marketing margins and crude runs were higher in the current quarter compared to the same quarter of 2003. Worldwide petroleum product sales averaged 353,538 barrels per day in 2004, a 38% increase from the third quarter of 2003. Worldwide refinery inputs were 173,677 barrels per day in the third quarter of 2004 compared to 72,484 barrels per day in the 2003 quarter. Inputs in the 2003 quarter were adversely affected by the Meraux refinery being out of service during the period due to a fire on June 10, 2003 and a planned refinery turnaround.

Refining and marketing operations in North America in the nine months of 2004 reported earnings of $29.8 million compared to a loss of $4.1 million. The improvement in the current period was primarily related to better operating results at the Meraux refinery. The 2004 period also included an after-tax gain of $3 million from the sale of most of the Company's jointly owned terminals in the U.S. Results in the United Kingdom reflected earnings of $22 million in the nine months ended September 30, 2004 compared to earnings of $5.8 million in 2003 due to higher margins compared to the same period a year ago.

Selected operating statistics for the three-month and nine-month periods ended September 30, 2004 and 2003 follow.

| | Three Months Ended September 30, | | Nine Months Ended September 30, | |
|---|---|---|---|---|
| | 2004 | 2003 | 2004 | 2003 |
| Refinery inputs – barrels per day | 173,677 | 72,484 | 175,469 | 123,400 |
| North America | 138,483 | 39,356 | 138,816 | 88,738 |
| United Kingdom | 35,194 | 33,128 | 36,653 | 34,662 |
| Petroleum products sold – barrels per day | 353,538 | 255,662 | 334,477 | 252,754 |
| North America | 317,835 | 220,543 | 297,697 | 218,105 |
| Gasoline | 210,707 | 167,752 | 204,324 | 155,084 |
| Kerosine | 721 | 293 | 3,193 | 4,572 |
| Diesel and home heating oils | 78,098 | 34,070 | 67,547 | 38,825 |
| Residuals | 13,953 | 4,629 | 13,180 | 10,575 |
| Asphalt, LPG and other | 14,356 | 13,799 | 9,453 | 9,049 |
| United Kingdom | 35,703 | 35,119 | 36,780 | 34,649 |
| Gasoline | 9,711 | 14,112 | 11,730 | 11,879 |
| Kerosine | 2,349 | 1,725 | 2,477 | 2,383 |
| Diesel and home heating oils | 14,366 | 13,596 | 14,456 | 13,754 |
| Residuals | 3,441 | 3,748 | 4,098 | 3,785 |
| LPG and other | 5,836 | 1,938 | 4,019 | 2,848 |

**Results of Operations (Contd.)**

*Corporate*

The after-tax cost of corporate activities, which include interest income and expense, foreign exchange gains and losses, and corporate overhead not allocated to operating functions, was $21.5 million in the third quarter 2004 compared to $3.7 million in the 2003 quarter. Losses on foreign exchange increased net after-tax costs in the 2004 period by $8.2 million, while the 2003 period included foreign currency gains of $5.4 million, net of taxes. Higher administrative expenses were the other primary reason for increased costs in 2004. In the nine months of 2004, corporate activities reflected a net cost of $46.8 million compared to a net cost of $1.3 million a year ago. The 2004 period included after-tax foreign exchange losses of $7.8 million, while 2003 included net foreign exchange gains of $5.4 million. Higher net interest and administrative expenses were also components of the increased costs in the 2004 period. The 2003 period included a benefit on U.S. tax settlements of $20.1 million.

**Financial Condition**

Net cash provided by continuing operations was $809.8 million for the nine months of 2004 compared to $419.6 million for the same period in 2003. Changes in operating working capital other than cash and cash equivalents provided cash of $59.1 million in 2004 and $43 million in 2003. Proceeds from the sale of assets provided cash of $59.5 million in 2004 compared to $77.9 million in 2003. Cash from operating activities was reduced by expenditures for major repairs and asset retirements totaling $14.7 million in 2004 and $60.6 million in 2003.

Other predominant uses of cash in each year were for dividends, which totaled $57.5 million in 2004 and $55.1 million in 2003, and for capital expenditures, which including amounts expensed, are summarized in the following table.

| (Millions of dollars) | Nine Months Ended September 30, 2004 | 2003 |
|---|---|---|
| Capital Expenditures – continuing operations | | |
| Exploration and production | $ 653.7 | 531.1 |
| Refining and marketing | 106.8 | 153.6 |
| Corporate and other | 1.1 | .8 |
| Total capital expenditures – continuing operations | 761.6 | 685.5 |
| Geological, geophysical and other exploration expenses charged to income | (30.4) | (28.8) |
| Total property additions and dry holes – continuing operations | $ 731.2 | 656.7 |

Working capital at September 30, 2004 was $842.2 million, up $613.7 million from December 31, 2003 with the increase primarily due to proceeds from sales of most of its Western Canadian conventional oil and natural gas assets in the second quarter of 2004. This level of working capital does not fully reflect the Company's liquidity position, because the lower historical costs assigned to inventories under LIFO accounting were $263.9 million below current costs at September 30, 2004.

**Financial Condition (Contd.)**

At September 30, 2004, long-term notes payable of $1,032.2 million were down $29.2 million from December 31, 2003 due to net repayments of amounts drawn under its existing revolving credit agreements. Long-term nonrecourse debt of a subsidiary was $14.8 million, down $14.1 million from December 31, 2003, primarily due to repayments. A summary of capital employed at September 30, 2004 and December 31, 2003 follows.

| | Sept. 30, 2004 | | Dec. 31, 2003 | |
|---|---|---|---|---|
| **(Millions of dollars)** | **Amount** | **%** | **Amount** | **%** |
| Capital Employed | | | | |
| Notes payable | $1,032.2 | 29.2 | $1,061.4 | 34.9 |
| Nonrecourse debt of a subsidiary | 14.8 | .4 | 28.9 | 1.0 |
| Stockholders' equity | 2,490.2 | 70.4 | 1,950.9 | 64.1 |
| Total capital employed | $3,537.2 | 100.0 | $3,041.2 | 100.0 |

**Accounting and Other Matters**

In July 2003 the FASB undertook to review whether mineral interests in properties (mineral leases) held by oil and gas companies should be recorded and disclosed as intangible assets under the guidance of SFAS No. 141, Business Combinations, and SFAS No. 142, Goodwill and Other Intangible Assets. After consideration of the matter, the FASB issued a staff position stating that drilling and mineral rights of oil and gas producing entities that are within the scope of SFAS 19 are not subject to the intangible asset classification and disclosure rules of SFAS No. 142. The staff position is consistent with the Company's present accounting practices and had no effect on its financial statements or disclosures.

SFAS No. 123, Accounting for Stock-Based Compensation, established accounting and disclosure requirements using a fair-value based method for stock-based compensation plans. As allowed by SFAS No. 123, the Company has elected to continue to apply the intrinsic-value based method prescribed by Accounting Principles Board Opinion No. 25 and has adopted only the disclosure requirements of SFAS No. 123. The FASB has issued a proposed statement that would amend SFAS No. 123 to require the Company to record in earnings the portion of stock-based compensation cost related to awards granted or modified after December 15, 1994 that is not vested at the time of adoption of the new standard. The FASB proposed statement would be effective for periods beginning after June 15, 2005.

Murphy holds a 20% interest in Block 16 Ecuador, where the Company and its partners produce oil for export. In 2001, the local tax authorities announced that Value Added Taxes (VAT) paid on goods and services related to Block 16 and many oil fields held by other companies will no longer be reimbursed. In response to this announcement, oil producers have filed actions in the Ecuador Tax Court seeking determination that the VAT in question is reimbursable. In July 2004, international arbitrators ruled that VAT was recoverable by another oil company, but the State of Ecuador responded that it was not bound by this arbitral decision. As of September 30, 2004, the Company has a receivable of approximately $10.9 million related to VAT. Murphy believes that its claim for reimbursement of VAT under applicable Ecuador tax law is valid, and it does not expect that the resolution of this matter will have a material adverse affect on the Company's financial position.

**Outlook**

Crude oil and natural gas sales prices have remained strong during October 2004. Production is expected to average approximately 111,000 barrels of oil equivalent per day in the fourth quarter 2004, after reduction by about 10,800 barrels of oil equivalent per day while storm repairs are completed in the Gulf of Mexico. Production from the Front Runner field in the deepwater Gulf of Mexico should start up late in the fourth quarter, and production from the field will ramp up into 2005 as new wells are brought on stream. In April, the Company's Board of Directors approved a development plan for the Kikeh field in deepwater Block K, Malaysia. PETRONAS and the Company's 20% partner, PETRONAS Carigali, approved the Kikeh development plan during the third quarter 2004. The development plan calls for first production in late 2007. North American gasoline marketing margins have weakened early in the fourth quarter 2004 compared to the just completed third quarter. The Company currently anticipates total capital expenditures in 2004 of approximately $1 billion.

**Forward-Looking Statements**

This Form 10-Q report contains statements of the Company's expectations, intentions, plans and beliefs that are forward-looking and are dependent on certain events, risks and uncertainties that may be outside of the Company's control. These forward-looking statements are made in reliance upon the safe harbor provisions of the Private Securities Litigation Reform Act of 1995. Actual results and developments could differ materially from those expressed or implied by such statements due to a number of factors including those described in the context of such forward-looking statements as well as those contained in the Company's January 15, 1997 Form 8-K report on file with the U.S. Securities and Exchange Commission.

## *ITEM 3. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK*

The Company is exposed to market risks associated with interest rates, prices of crude oil, natural gas and petroleum products, and foreign currency exchange rates. As described in Note D to this Form 10-Q report, Murphy makes use of derivative financial and commodity instruments to manage risks associated with existing or anticipated transactions.

The Company was a party to interest rate swaps at September 30, 2004 with notional amounts totaling $15 million that were designed to hedge fluctuations in cash flows of a similar amount of variable-rate debt. These swaps mature in October 2004. The swaps require the Company to pay an average interest rate of 5.98% over their composite lives, and at September 30, 2004, the interest rate to be received by the Company averaged 1.68%. The variable interest rate received by the Company under each swap contract is repriced quarterly. The estimated fair value of these interest rate swaps was recorded as a liability of $.2 million at September 30, 2004, with the offsetting loss recorded in Accumulated Other Comprehensive Income (AOCI) in Stockholders' Equity.

At September 30, 2004, 39% of the Company's debt had variable interest rates and approximately 2% was denominated in Canadian dollars. Based on debt outstanding at September 30, 2004, a 10% increase in variable interest rates would increase the Company's interest expense approximately $1.3 million for the next 12 months after including the favorable effect resulting from lower net settlement payments under the aforementioned interest rate swaps.

Murphy was a party to natural gas price swap agreements at September 30, 2004 for a remaining notional volume of 3.9 million MMBTU that are intended to hedge the financial exposure of its Meraux, Louisiana and Superior, Wisconsin refineries to fluctuations in the future price of a portion of natural gas to be purchased for fuel through 2006. In each month of settlement, the swaps require Murphy to pay an average natural gas price of $2.78 per MMBTU and to receive the average NYMEX price for the final three trading days of the month. At September 30, 2004, the estimated fair value of these agreements was recorded as an asset of $14 million. A 10% increase in the average NYMEX price of natural gas would have increased this asset by $2.6 million, while a 10% decrease would have reduced the asset by a similar amount. Additionally, the Company was a party to natural gas price swap agreements at September 30, 2004 for a total remaining notional volume of .6 million MMBTU that effectively fixed the settlement price for the natural gas purchase swaps maturing in October 2004. The terms are nearly identical to the aforementioned swaps and require Murphy to pay the average NYMEX price for the final three trading days of the month and receive an average natural gas price of $5.235 per MMBTU. At September 30, 2004 the estimated fair value of these agreements was recorded as a liability of $.1 million. A 10% change in the average NYMEX index price of natural gas would not have a significant impact on this liability.

At September 30, 2004, the Company was a party to natural gas put options covering .8 million MMBTU in future natural gas sales during October 2004. The options are intended to hedge the financial exposure of the Company's natural gas sales in the U.S. should the future selling price during the contract period fall below a $4.00 per MMBTU floor price. At September 30, 2004, the estimated fair value of these agreements was recorded as an asset valued at less than $.1 million. A 10% change in the price of natural gas would not have a significant impact on the fair value of this asset.

At September 30, 2004, the Company was a party to forward sale contracts covering 2,000 barrels per day in heavy oil sales during 2005 and 2006. The contracts are intended to hedge the financial exposure of the Company's heavy oil sales in Canada during the respective contract period and are priced at $29.00 per barrel in 2005 and $24.70 per barrel in 2006. At September 30, 2004, the estimated fair value of these agreements was recorded as a liability valued at $4.2 million. A 10% increase in the price of Canadian heavy oil at the Hardisty terminal in Canada would have increased this liability by $4 million, while a 10% decrease would have reduced this liability by a similar amount.

### *ITEM 4. CONTROLS AND PROCEDURES*

The Company, under the direction of its principal executive officer and principal financial officer, has established controls and procedures to ensure that material information relating to the Company and its consolidated subsidiaries is made known to the officers who certify the Company's financial reports and to other members of senior management and the Board of Directors.

Based on the Company's evaluation as of the end of the period covered by the filing of this Quarterly Report on Form 10-Q, the principal executive officer and principal financial officer of Murphy Oil Corporation have concluded that the Company's disclosure controls and procedures (as defined in Rules 13a-15 under the Securities Exchange Act of 1934) are effective to ensure that the information required to be disclosed by Murphy Oil Corporation in reports that it files or submits under the Securities Exchange Act of 1934 is recorded, processed, summarized and reported within the time periods specified in SEC rules and forms.

There were no significant changes in the Company's internal controls over financial reporting that occurred during the third quarter of 2004 that have materially affected, or are reasonably likely to materially affect, the Company's internal control over financial reporting.

## PART II – OTHER INFORMATION

### *ITEM 1. LEGAL PROCEEDINGS*

In December 2000, two of the Company's Canadian subsidiaries, Murphy Oil Company Ltd. (MOCL) and Murphy Canada Exploration Company (MCEC) as plaintiffs filed an action in the Court of Queen's Bench of Alberta seeking a constructive trust over oil and gas leasehold rights to Crown lands in British Columbia. The suit alleges that the defendants, the Predator Corporation Ltd. and Predator Energies Partnership (collectively Predator) and Ricks Nova Scotia Co. (Ricks), acquired the lands after first inappropriately obtaining confidential and proprietary data belonging to the Company and its partner. In January 2001, Ricks, representing an undivided 75% interest in the lands in question, settled its portion of the litigation by conveying its interest to the Company and its partner at cost. In 2001, Predator, representing the remaining undivided 25% of the lands in question, filed a counterclaim, as subsequently amended, against MOCL and MCEC and MOCL's president individually seeking compensatory damages of C$3.61 billion. In September 2004 the court summarily dismissed all claims against MOCL's president and all but C$356 million of the counterclaim against the Company; however, this dismissal order is currently on appeal. It is anticipated that a trial concerning the 25% disputed interest and any remaining issues will commence in 2005. While the litigation is in the discovery stage and no assurance can be given about the outcome, the Company does not believe that the ultimate resolution of this suit will have a material adverse effect on its financial condition or its results of operations.

On June 10, 2003, a fire severely damaged the Residual Oil Supercritical Extraction (ROSE) unit at the Company's Meraux, Louisiana refinery. The ROSE unit recovers feedstock from the heavy fuel oil stream for conversion into gasoline and diesel. Subsequent to the fire, numerous class action lawsuits have been filed seeking damages for area residents. All the lawsuits have been administratively consolidated into a single legal action in St. Bernard Parish, Louisiana, except for one such action which was filed in federal court. Additionally, individual residents of Orleans Parish, Louisiana, have filed an action in that venue. On May 5, 2004, plaintiffs in the consolidated action in St. Bernard Parish amended their petition to include a direct action against certain of the Company's liability insurers. In responding to this direct action, one of the Company's insurers, AEGIS, has raised lack of coverage as a defense. The Company believes that this contention lacks merit and has been advised by counsel that the applicable policy does provide coverage for the underlying incident. The Company continues to believe that the ultimate resolution of the June 2003 ROSE fire litigation will not have a material adverse effect on its financial condition.

On March 5, 2002, two of the Company's subsidiaries filed suit against Enron Canada Corp. (Enron) to collect approximately $2.1 million owed to Murphy under canceled gas sales contracts. On May 1, 2002, Enron counterclaimed for approximately $19.8 million allegedly owed by Murphy under those same agreements. Although the lawsuit in the Court of Queen's Bench, Alberta, is in its early stages and no assurance can be given about the outcome, the Company does not believe that the Enron counterclaim is meritorious and does not believe that the ultimate resolution of this matter will have a material adverse effect on its financial condition.

Murphy and its subsidiaries are engaged in a number of other legal proceedings, all of which Murphy considers routine and incidental to its business and none of which is expected to have a material adverse effect on the Company's financial condition. Based on information currently available to the Company, the ultimate resolution of matters referred to in this item is not expected to have a material adverse effect on the Company's earnings or financial condition in a future period.

***ITEM 6. EXHIBITS AND REPORTS ON FORM 8-K***

(a) The Exhibit Index on page 26 of this Form 10-Q report lists the exhibits that are hereby filed or incorporated by reference.

(b) A report on Form 8-K was filed on July 27, 2004 that included a News Release announcing the Company’s earnings and certain other financial information for the three-month and six-month period ended on June 30, 2004.

(c) A report on Form 8-K was filed on August 6, 2004 that included a press release announcing the election of Mr. Neal Schmale as a director of the Company. Additionally, the Form 8-K included the amended By-Laws of the Company effective August 4, 2004.

**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.

***MURPHY OIL CORPORATION***
*(Registrant)*

By /s/ JOHN W. ECKART

John W. Eckart, Controller
*(Chief Accounting Officer and Duly Authorized Officer)*

November 5, 2004
*(Date)*

## EXHIBIT INDEX

| Exhibit No. | |
|---|---|
| 12.1* | Computation of Ratio of Earnings to Fixed Charges |
| 31.1* | Certification pursuant to Section 302 of the Sarbanes-Oxley Act of 2002 |
| 31.2* | Certification pursuant to Section 302 of the Sarbanes-Oxley Act of 2002 |
| 32 | Certification pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002 |

* This exhibit is incorporated by reference within this Form 10-Q.

Exhibits other than those listed above have been omitted since they are either not required or not applicable.

**EXHIBIT 12.1**

Murphy Oil Corporation and Consolidated Subsidiaries

**Computation of Ratio of Earnings to Fixed Charges (unaudited)**

(Thousands of Dollars)

| | Nine Months Ended Sept. 30, 2004 | Year Ended December 31, 2003 | 2002 | 2001 | 2000 | 1999 |
|---|---|---|---|---|---|---|
| Income from continuing operations before income taxes | $ 593,859 | 374,205 | 122,067 | 437,342 | 406,086 | 153,185 |
| Distributions (less than) greater than equity in earnings of affiliates | (3,205) | (209) | (3) | (365) | (34) | 64 |
| Previously capitalized interest charged to earnings during period | 10,737 | 10,457 | 7,748 | 3,450 | 3,507 | 3,146 |
| Interest and expense on indebtedness, excluding capitalized interest | 27,242 | 20,511 | 26,968 | 19,006 | 16,337 | 20,274 |
| Interest portion of rentals* | 5,770 | 9,857 | 9,445 | 7,953 | 5,808 | 3,267 |
| **Earnings before provision for taxes and fixed charges** | **$ 634,403** | **414,821** | **166,225** | **467,386** | **431,704** | **179,936** |
| Interest and expense on indebtedness, excluding capitalized interest | 27,242 | 20,511 | 26,968 | 19,006 | 16,337 | 20,274 |
| Capitalized interest | 15,083 | 37,240 | 24,536 | 20,283 | 13,599 | 7,865 |
| Interest portion of rentals* | 5,770 | 9,857 | 9,445 | 7,953 | 5,808 | 3,267 |
| **Total fixed charges** | **$ 48,095** | **67,608** | **60,949** | **47,242** | **35,744** | **31,406** |
| **Ratio of earnings to fixed charges** | **13.2** | **6.1** | **2.7** | **9.9** | **12.1** | **5.7** |

* Calculated as one-third of rentals. Considered a reasonable approximation of interest factor.

**EXHIBIT 31.1**

**CERTIFICATION PURSUANT TO**
**SECTION 302 OF THE SARBANES-OXLEY ACT OF 2002**

I, Claiborne P. Deming, certify that:

1. I have reviewed this quarterly report on Form 10-Q of Murphy Oil Corporation;
2. Based on my knowledge, this quarterly 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 quarterly report;
3. Based on my knowledge, the financial statements, and other financial information included in this quarterly 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 quarterly 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 we 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 controls 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 function):
   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 controls over financial reporting.

Date: November 5, 2004

/s/ Claiborne P. Deming

Claiborne P. Deming
Principal Executive Officer

**EXHIBIT 31.2**

**CERTIFICATION PURSUANT TO**
**SECTION 302 OF THE SARBANES-OXLEY ACT OF 2002**

I, Steven A. Cossé, certify that:

1. I have reviewed this quarterly report on Form 10-Q of Murphy Oil Corporation;

2. Based on my knowledge, this quarterly 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 quarterly report;

3. Based on my knowledge, the financial statements, and other financial information included in this quarterly 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 quarterly 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 we 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 controls 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 function):

   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 controls over financial reporting.

Date: November 5, 2004

/s/ Steven A. Cossé

Steven A. Cossé
Principal Financial Officer

**CERTIFICATION PURSUANT TO
18 U.S.C. SECTION 1350,
AS ADOPTED PURSUANT TO
SECTION 906 OF THE SARBANES-OXLEY ACT OF 2002**

In connection with the Quarterly Report of Murphy Oil Corporation (the “Company”) on Form 10-Q for the period ended September 30, 2004 as filed with the Securities and Exchange Commission on the date hereof (the “Report”), we, Claiborne P. Deming and Steven A. Cossé, Principal Executive Officer and Principal Financial Officer, respectively, of the Company, certify, pursuant to 18 U.S.C. § 1350, as adopted pursuant to § 906 of the Sarbanes-Oxley Act of 2002, that to our knowledge:

(1) The Report fully complies with the requirements of section 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.

November 5, 2004

/s/ Claiborne P. Deming

Claiborne P. Deming
Principal Executive Officer

/s/ Steven A. Cossé

Steven A. Cossé
Principal Financial Officer