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 June 30, 2004

OR

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

For the transition period from ______ to ______

Commission File Number 1-8590

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

Delaware **(State or other jurisdiction of incorporation or organization)**	**71-0361522** **(I.R.S. Employer Identification Number)**
200 Peach Street **P. O. Box 7000, El Dorado, Arkansas** **(Address of principal executive offices)**	**71731-7000** **(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 June 30, 2004 was **92,004,733.**

PART I – FINANCIAL INFORMATION

ITEM 1. FINANCIAL STATEMENTS

Murphy Oil Corporation and Consolidated Subsidiaries

CONSOLIDATED BALANCE SHEETS

(Thousands of dollars)

	(Unaudited) June 30, 2004	December 31, 2003
ASSETS		
Current assets		
Cash and cash equivalents	$ 947,009	252,425
Accounts receivable, less allowance for doubtful accounts of $11,272 in 2004 and $10,735 in 2003	640,344	450,201
Inventories, at lower of cost or market		
Crude oil and blend stocks	84,710	46,626
Finished products	134,756	157,078
Materials and supplies	64,984	66,806
Prepaid expenses	47,769	44,779
Deferred income taxes	27,548	20,940
Total current assets	1,947,120	1,038,855
Property, plant and equipment, at cost less accumulated depreciation, depletion and amortization of $2,983,716 in 2004 and $3,472,133 in 2003	3,244,619	3,530,800
Goodwill, net	39,191	64,873
Deferred charges and other assets	70,432	78,119
Total assets	$5,301,362	4,712,647
LIABILITIES AND STOCKHOLDERS' EQUITY		
Current liabilities		
Current maturities of long-term debt	$ 61,642	67,224
Accounts payable and accrued liabilities	857,429	659,609
Income taxes	151,842	83,493
Total current liabilities	1,070,913	810,326
Notes payable	1,032,798	1,061,410
Nonrecourse debt of a subsidiary	14,046	28,897
Deferred income taxes	419,954	421,700
Asset retirement obligations	200,855	252,397
Accrued major repair costs	30,718	20,513
Deferred credits and other liabilities	181,498	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	509,594	504,809
Retained earnings	1,769,228	1,357,910
Accumulated other comprehensive income	50,717	65,246
Unamortized restricted stock awards	(5,479)	—
Treasury stock, 2,608,646 shares of Common Stock in 2004 and 2,742,781 shares in 2003 at cost	(68,093)	(71,695)
Total stockholders' equity	2,350,580	1,950,883
Total liabilities and stockholders' equity	$5,301,362	4,712,647

See Notes to Consolidated Financial Statements, page 5.

The Exhibit Index is on page 27.

Murphy Oil Corporation and Consolidated Subsidiaries

CONSOLIDATED STATEMENTS OF INCOME (unaudited)

(Thousands of dollars except per share amounts)

	Three Months Ended June 30, 2004	Three Months Ended June 30, 2003*	Six Months Ended June 30, 2004	Six Months Ended June 30, 2003*
REVENUES				
Sales and other operating revenues	$ 2,087,060	1,172,895	3,703,626	2,430,065
Gain on sale of assets	1,593	49,274	30,800	49,298
Interest and other income	7,114	1,220	9,413	2,195
Total revenues	2,095,767	1,223,389	3,743,839	2,481,558
COSTS AND EXPENSES				
Crude oil, natural gas and product purchases	1,507,177	839,739	2,674,442	1,744,432
Operating expenses	180,026	151,599	348,436	294,495
Exploration expenses, including undeveloped lease amortization	23,209	28,048	72,358	43,447
Selling and general expenses	33,194	27,189	63,875	56,122
Depreciation, depletion and amortization	82,714	59,125	162,910	116,301
Accretion of asset retirement obligations	2,467	2,490	4,974	4,961
Interest expense	14,179	14,272	28,467	28,233
Interest capitalized	(4,814)	(10,112)	(9,066)	(19,648)
Total costs and expenses	1,838,152	1,112,350	3,346,396	2,268,343
Income from continuing operations before income taxes	257,615	111,039	397,443	213,215
Income tax expense	89,480	38,684	148,612	58,003
Income from continuing operations	168,135	72,355	248,831	155,212
Discontinued operations, net of tax	181,738	7,331	199,281	18,579
Income before cumulative effect of change in accounting principle	349,873	79,686	448,112	173,791
Cumulative effect of change in accounting principle, net of tax	—	—	—	(6,993)
NET INCOME	$ 349,873	79,686	448,112	166,798
INCOME (LOSS) PER COMMON SHARE – BASIC				
Income from continuing operations	$ 1.82	.79	2.70	1.69
Discontinued operations	1.98	.08	2.17	.21
Cumulative effect of change in accounting principle	—	—	—	(.08)
NET INCOME – BASIC	$ 3.80	.87	4.87	1.82
INCOME (LOSS) PER COMMON SHARE – DILUTED				
Income from continuing operations	$ 1.80	.78	2.67	1.68
Discontinued operations	1.95	.08	2.14	.20
Cumulative effect of change in accounting principle	—	—	—	(.08)
NET INCOME – DILUTED	$ 3.75	.86	4.81	1.80
Average common shares outstanding – basic	91,994,700	91,817,165	91,957,965	91,776,458
Average common shares outstanding – diluted	93,341,176	92,503,242	93,253,067	92,464,624

* 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 June 30,		Six Months Ended June 30,	
	2004	**2003**	**2004**	**2003**
Net income	$ 349,873	79,686	448,112	166,798
Other comprehensive income, net of tax				
Cash flow hedges				
Net derivative gains (losses)	1,980	(4,468)	4,368	(24,155)
Reclassification adjustments	(2,366)	8,689	(5,474)	27,138
Total cash flow hedges	(386)	4,221	(1,106)	2,983
Net gain (loss) from foreign currency translation	(8,555)	90,456	(13,423)	143,103
Minimum pension liability adjustment	—	—	—	(707)
COMPREHENSIVE INCOME	$ 340,932	174,363	433,583	312,177

See Notes to Consolidated Financial Statements, page 5.

Murphy Oil Corporation and Consolidated Subsidiaries

CONSOLIDATED STATEMENTS OF CASH FLOWS (unaudited)

(Thousands of dollars)

	Six Months Ended June 30, 2004	Six Months Ended June 30, 2003
OPERATING ACTIVITIES		
Income from continuing operations	$ 248,831	155,212
Adjustments to reconcile income from continuing operations to net cash provided by operating activities		
Depreciation, depletion and amortization	162,910	116,301
Provisions for major repairs	15,177	15,830
Expenditures for major repairs and asset retirement obligations	(8,989)	(26,193)
Dry hole costs	50,596	19,365
Amortization of undeveloped leases	7,608	6,970
Accretion of asset retirement obligations	4,974	4,961
Deferred and noncurrent income tax charges	47,690	5,640
Pretax gains from disposition of assets	(30,800)	(49,298)
Net (increase) decrease in operating working capital other than cash and cash equivalents	(1,848)	6,107
Other	(1,265)	(5,672)
Net cash provided by continuing operations	494,884	249,223
Net cash provided by discontinued operations	60,272	89,909
Net cash provided by operating activities	555,156	339,132
INVESTING ACTIVITIES		
Property additions and dry hole costs	(398,148)	(417,350)
Proceeds from sales of assets	40,671	69,035
Other – net	(1,302)	80
Investing activities of discontinued operations:		
Sales proceeds	582,675	—
Other	(13,529)	(35,885)
Net cash provided (required) by investing activities	210,367	(384,120)
FINANCING ACTIVITIES		
Increase (decrease) in notes payable	(27,549)	149,488
Decrease in nonrecourse debt of a subsidiary	(20,899)	(24,452)
Proceeds from exercise of stock options and employee stock purchase plans	1,886	2,348
Cash dividends paid	(36,794)	(36,718)
Other	—	(72)
Net cash provided by (used in) financing activities	(83,356)	90,594
Effect of exchange rate changes on cash and cash equivalents	12,417	9,705
Net increase in cash and cash equivalents	694,584	55,311
Cash and cash equivalents at January 1	252,425	164,957
Cash and cash equivalents at June 30	$ 947,009	220,268
SUPPLEMENTAL DISCLOSURES OF CASH FLOW ACTIVITIES		
Cash income taxes paid, net of refunds	$ 96,988	16,583
Interest paid, net of amounts capitalized	18,357	7,057

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 June 30, 2004, and the results of operations and cash flows for the three-month and six-month periods ended June 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 six months ended June 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 sale of assets under one agreement occurred on April 22, 2004 and the other transaction was finalized on May 31, 2004. The Company recorded a gain of $166.7 million, net of $23.7 million in income taxes, upon 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. 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 six-month periods ended June 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	412,301
Goodwill, net	23,091
Other noncurrent assets	4,214
Assets sold	$442,254
Deferred income taxes	$ (25,099)
Asset retirement obligations	(49,969)
Liabilities associated with assets sold	$ (75,068)

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

	Three Months Ended June 30,		Six Months Ended June 30,	
(Thousands of dollars)	2004	2003	2004	2003
Revenues, including a pretax gain on sale of assets of $190,390 in 2004 periods	$ 217,256	54,187	269,972	118,331
Income before income tax expense	209,214	16,907	238,083	40,022
Income tax expense	27,476	9,576	38,802	21,443

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.

Note C – Employee and Retiree Pension and Postretirement Plans ***(Contd.)***

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 six-month periods ended June 30, 2004 and 2003.

	Three Months Ended June 30,			
	2004	2003	2004	2003
(Thousands of dollars)	Pension Benefits		Postretirement Benefits	
Service cost	$ 2,315	2,359	316	320
Interest cost	4,929	5,972	856	957
Expected return on plan assets	(4,726)	(5,666)	—	—
Amortization of prior service cost	(68)	(583)	(180)	(25)
Amortization of transitional asset	101	149	—	—
Recognized actuarial loss	1,069	1,207	455	346
	3,620	3,438	1,447	1,598
Settlement gain	(534)	—	—	—
Net periodic benefit expense	$ 3,086	3,438	1,447	1,598

	Six Months Ended June 30,			
	2004	2003	2004	2003
(Thousands of dollars)	Pension Benefits		Postretirement Benefits	
Service cost	$ 4,677	4,430	678	636
Interest cost	9,889	11,022	1,838	1,899
Expected return on plan assets	(9,492)	(10,423)	—	—
Amortization of prior service cost	(139)	(1,069)	(386)	(49)
Amortization of transitional asset	203	275	—	—
Recognized actuarial loss	2,140	2,192	978	687
	7,278	6,427	3,108	3,173
Settlement gain	(534)	—	—	—
Net periodic benefit expense	$ 6,744	6,427	3,108	3,173

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 June 30, 2004, $.8 million and $1.1 million of contributions have been made to the domestic defined benefit pension plans and postretirement benefits plan, respectively. Murphy presently anticipates contributing during the last six months of 2004 an additional $5.9 million in the aggregate to fund its domestic plans. Murphy also anticipates contributing $1.5 million in the last six 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 $9.3 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. The Company recognized $.4 million in estimated benefits related to the Act in the first half of 2004. The Financial Accounting Standards Board has issued a FASB Staff Position that will require additional disclosures in future periods.

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.

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

- *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 $30 million at June 30, 2004 to hedge fluctuations in cash flows of a similar amount of variable rate debt. The swaps mature in July and October 2004. Under the interest rate swaps, the Company pays fixed rates averaging 6.06% over their composite lives and receives variable rates which averaged 1.16% at June 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 June 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 June 30, 2004 of 5.7 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 Crude Oil, Natural Gas and Product Purchases 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 1.8 million MMBTU no longer qualified as a cash flow hedge. Therefore, .7 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 1.0 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 June 30, 2004, the income effect from cash flow hedging ineffectiveness for these contracts was $.2 million, net of $.1 million in income taxes. For the period ended June 30, 2003, the income effect from ineffectiveness was insignificant. During the six-month period ended June 30, 2004, the Company received approximately $9.9 million for maturing swap agreements.
- *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 from July 2004 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

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

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 six-month periods ended June 30, 2004 and 2003, Murphy's earnings were not significantly affected by cash flow hedging ineffectiveness.

During the six-month period ended June 30, 2003, the Company paid $10.6 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. 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 were 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 first six-months of 2003, cash flow hedging ineffectiveness relating to the crude oil sales swaps increased Murphy's after-tax earnings by $1.4 million.

  During the six-month period ended June 30, 2003 the Company paid $36.9 million for settlement of maturing crude oil swaps.

  The fair value of the crude oil sales swaps are 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 twelve months, the Company expects to reclassify approximately $5.6 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

Note E – Asset Retirement Obligations (Contd.)

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, including 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 June 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 its investment in 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	6,183	6,285
Liabilities incurred	8,276	14,150
Liabilities settled	(55,049)	(57,140)
Revisions of previous estimates	(5,393)	—
Changes due to translation of foreign currencies	(5,559)	16,627
Balance at June 30	$200,855	232,965

Accretion expense of $1.2 million and $1.3 million shown in the above table were included in discontinued operating results for the six months ended June 30, 2004 and 2003, respectively. Liabilities settled in 2004 and 2003 included approximately $50.8 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 six-month periods ended June 30, 2004 and 2003. The following table reconciles the weighted-average shares outstanding used for these computations.

	Three Months Ended June 30,		Six Months Ended June 30,	
(Weighted-average shares)	2004	2003	2004	2003
Basic method	91,994,700	91,817,165	91,957,965	91,776,458
Dilutive stock options	1,346,476	686,077	1,295,102	688,166
Diluted method	93,341,176	92,503,242	93,253,067	92,464,624

The computation of earnings per share in the Consolidated Statements of Income did not consider outstanding options of 54,000 shares for the six-month period ended June 30, 2003 because the effects of these options would have been antidilutive. Average exercise prices of the options not used were $47.16 per share. There were no antidilutive options for the three-month periods ended June 30, 2004 and 2003 and the six-month period ended June 30, 2004.

Note F – Earnings per Share and Stock Options (Contd.)

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 six-month periods ended June 30, 2004 and 2003 would be the pro forma amounts shown in the table below.

	Three Months Ended June 30,		Six Months Ended June 30,	
(Thousands of dollars except per share data)	**2004**	**2003**	**2004**	**2003**
Net income – As reported	$ 349,873	79,686	448,112	166,798
Restricted stock compensation expense included in income, net of tax	317	—	511	197
Total stock-based compensation expense using fair value method for all awards, net of tax	(1,537)	(1,364)	(3,021)	(2,628)
Net income – Pro forma	$ 348,653	78,322	445,602	164,367
Net income per share – As reported, basic	$ 3.80	.87	4.87	1.82
Pro forma, basic	3.79	.85	4.85	1.79
As reported, diluted	3.75	.86	4.81	1.80
Pro forma, diluted	3.74	.84	4.78	1.76

Note G – Accumulated Other Comprehensive Income

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

(Thousands of dollars)	**June 30, 2004**	**December 31, 2003**
Foreign currency translation gain	$ 75,166	88,589
Cash flow hedging, net	8,352	9,458
Minimum pension liability, net	(32,801)	(32,801)
Accumulated other comprehensive income	$ 50,717	65,246

The effect of SFAS Nos. 133/138, Accounting for Derivative Instruments and Hedging Activities, decreased AOCI for the three months ended June 30, 2004 by $.4 million, net of $.2 million in income taxes, and hedging ineffectiveness increased net income by $.3 million, net of $.1 in income taxes. During the six-month period ended June 30, 2004, hedging activities decreased AOCI by $1.1 million, net of $.6 million in income taxes, and hedging ineffectiveness increased income by $.3 million, net of $.1 million in income taxes. Gains of $5.5 million, net of $2.9 million in taxes, were reclassified from AOCI to earnings in the six-month period ended June 30, 2004. During the three month period ended June 30, 2003, AOCI increased by $4.2 million, net of $2.4 million in income taxes, and hedging ineffectiveness increased net income by $.8 million, net of $.4 million in income taxes. During the first half of 2003, hedging activities increased AOCI by $3 million, net of $1.2 million in income taxes, and hedging ineffectiveness increased income by $1.4 million, net of $.9 million in income taxes. For the first half of 2003 losses of $27.1 million, net of $19.2 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. The Company believes that the counterclaim is without merit and that the amount of damages sought is frivolous. Trial will likely begin in January 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.

Note I – Other Contingencies (Contd.)

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 June 30, 2004, the Company had contingent liabilities of $9 million under a financial guarantee and $42.6 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 – Business Segments

(Millions of dollars)	Total Assets at June 30, 2004	Three Months Ended June 30, 2004 External Revenues	Inter - segment Revenues	Income (Loss)	Three Months Ended June 30, 2003 External Revenues	Inter - segment Revenues	Income (Loss)
Exploration and production*							
United States	$ 805.0	131.7	—	47.7	49.9	—	2.8
Canada	1,082.8	120.9	27.6	64.5	92.2	12.3	35.1
United Kingdom	207.4	41.7	—	15.8	91.4	—	47.4
Ecuador	109.6	13.7	—	3.8	4.8	—	.8
Malaysia	368.4	43.9	—	10.6	—	—	(5.3)
Other	22.8	.6	—	(2.6)	1.6	—	(.5)
Total	2,596.0	352.5	27.6	139.8	239.9	12.3	80.3
Refining and marketing							
North America	1,462.3	1,564.1	—	27.4	866.2	—	(1.5)
United Kingdom	237.9	172.0	—	12.1	116.1	—	1.8
Total	1,700.2	1,736.1	—	39.5	982.3	—	.3
Total operating segments	4,296.2	2,088.6	27.6	179.3	1,222.2	12.3	80.6
Corporate and other	1,005.2	7.1	—	(11.2)	1.2	—	(8.3)
Total from continuing operations	5,301.4	2,095.7	27.6	168.1	1,223.4	12.3	72.3
Discontinued operations	—	—	—	181.8	—	—	7.4
Total	$ 5,301.4	2,095.7	27.6	349.9	1,223.4	12.3	79.7

(Millions of dollars)	Six Months Ended June 30, 2004 External Revenues	Inter - segment Revenues	Income (Loss)	Six Months Ended June 30, 2003 External Revenues	Inter - segment Revenues	Income (Loss)
Exploration and production*						
United States	$ 263.0	—	84.2	100.6	—	15.6
Canada	233.4	57.6	118.1	196.7	25.3	79.8
United Kingdom	80.1	—	29.6	149.6	—	66.5
Ecuador	30.1	—	6.7	16.1	—	6.3
Malaysia	69.5	—	6.6	—	—	(10.8)
Other	1.6	—	(4.2)	2.3	—	(1.4)
Total	677.7	57.6	241.0	465.3	25.3	156.0
Refining and marketing						
North America	2,751.9	—	16.9	1,775.7	—	(7.9)
United Kingdom	304.8	—	16.2	238.4	—	4.7
Total	3,056.7	—	33.1	2,014.1	—	(3.2)
Total operating segments	3,734.4	57.6	274.1	2,479.4	25.3	152.8
Corporate and other	9.4	—	(25.3)	2.2	—	2.4
Total from continuing operations	3,743.8	57.6	248.8	2,481.6	25.3	155.2
Discontinued operations	—	—	199.3	—	—	18.6
Cumulative effect of change in accounting principle	—	—	—	—	—	(7.0)
Total	$ 3,743.8	57.6	448.1	2,481.6	25.3	166.8

* Additional details about results of oil and gas operations are presented in the tables on page 19.

Note K – 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. The FASB is considering whether an oil and gas company's investment in mineral leases should be classified as intangible assets. SFAS No. 141 and SFAS No. 142 established new accounting guidelines for both finite lived intangible assets and indefinite lived intangible assets. Under SFAS No. 141 and SFAS No. 142, intangible assets should be separately reported on the Balance Sheet, with accompanying disclosures in the notes to the financial statements. SFAS No. 142 does not change the accounting prescribed in SFAS No. 19, Financial Accounting and Reporting by Oil and Gas Producing Companies, and is silent about whether its disclosure provisions apply to oil and gas companies. The Company does not believe that SFAS No. 141 and SFAS No. 142 change the classification and disclosure of oil and gas mineral leases and it continues to classify these assets as part of Property, Plant and Equipment in the Consolidated Balance Sheet and does not provide the additional disclosures for these assets. The FASB has issued a proposed 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. Should the FASB proposed staff position not be adopted and it is determined that oil and gas mineral leases are intangible assets in accordance with SFAS No. 141 and SFAS No. 142, the Company would reclassify $112 million and $143 million as intangible undeveloped mineral interests at June 30, 2004 and December 31, 2003, respectively. In addition, a reclassification of $5 million and $8 million would be made as intangible developed mineral interests at June 30, 2004 and December 31, 2003, respectively. Both intangible assets would be presented net of accumulated amortization. Historically, undeveloped mineral leases have been amortized over the life of the lease period, while developed mineral leases have been amortized using the units of production method over the expected life of proved reserves. The amounts included herein are based on our understanding of the issue on the EITF's agenda. If all mineral leases associated with oil and gas properties are deemed to be intangible assets in accordance with SFAS No. 141 and SFAS No. 142 by the EITF:

- These assets would not be included in Property, Plant and Equipment on our Consolidated Balance Sheet
- We do not believe that our net income or cash flows from operations would be materially affected because the amortization of these assets would not be different than the method currently used by the Company
- Disclosures required by SFAS No. 141 and SFAS No. 142 relative to intangible assets would be included in the notes to the financial statements.

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

Results of Operations

Murphy's net income in the second quarter of 2004 was a record $349.9 million, $3.75 per diluted share, compared to net income of $79.7 million, $.86 per diluted share, in the second quarter of 2003. Net income in the current period included income from discontinued operations of $181.8 million, $1.95 per share, $166.7 million of which was a net gain on sale of most conventional oil and gas assets in Western Canada. Discontinued operations income in the second quarter of 2003 was $7.4 million, $.08 per share. Income from continuing operations in the second quarter of 2004 was also a record $168.1 million, $1.80 per share, compared to $72.3 million, $.78 per share, in the same period in 2003.

In the current quarter, the Company's exploration and production operations earned $139.8 million, an increase of $59.5 million from $80.3 million earned in the 2003 period. The earnings improvement in 2004 was primarily caused by higher oil and gas sales prices and sales volumes. The 2003 period included a $34 million after-tax gain on sale of North Sea properties. The Company's refining and marketing operations generated income of $39.5 million in the second quarter of 2004 compared to income of $.3 million for the three months ended June 30, 2003. The improvement was due to significantly better margins in North America and the United Kingdom in the current quarter. A fire that destroyed the ROSE unit at the Meraux, Louisiana refinery in June 2003 lowered earnings in the second quarter of 2003 by $12.3 million. The after-tax costs of the corporate function were $11.2 million in the 2004 second quarter compared to $8.3 million in the 2003 quarter. Higher administrative expenses were the primary reasons for increased costs in 2004.

For the first six months of 2004, net income totaled $448.1 million, $4.81 per diluted share, compared to $166.8 million, $1.80 per diluted share, for the first half of 2003. Income from discontinued operations was $199.3 million, $2.14 per share in the first half of 2004, while the same period in 2003 totaled $18.6 million, $.20 per share. Continuing operations earned $248.8 million, $2.67 per share, in 2004 and $155.2 million, $1.68 per share, in 2003. Additionally in 2003, upon adoption of Statement of Financial Accounting Standards No. 143, Accounting for Asset Retirement Obligations, effective January 1, 2003, the Company recorded in the income statement an after-tax charge of $7 million, $.08 per share, as the cumulative effect of a change in accounting principle.

Exploration and production earnings in the first six months of 2004 were up $85 million from the prior year, mainly due to higher oil and natural gas sales prices and sales volumes in the 2004 period, partially offset by lower gains on sale of assets and higher exploration expenses. The Company's refining and marketing operations generated a profit of $33.1 million in the first half of 2004, but incurred a loss of $3.2 million in the 2003 period. The improved current year result was based on strong margins in both the North American and U.K. businesses in the second quarter of 2004 coupled with $12.3 million of after-tax costs in the 2003 period resulting from a fire at the Meraux refinery. Corporate after-tax costs were $25.3 million in the first six months of 2004 compared to a profit of $2.4 million in the 2003 period. The prior year included a benefit on U.S. tax settlements of $20.1 million. Higher net interest and administrative expenses were also components of the higher costs in the 2004 period.

Exploration and Production

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

	Income (Loss)			
	Three Months Ended June 30,		Six Months Ended June 30,	
(Millions of dollars)	2004	2003	2004	2003
Exploration and production				
United States	$ 47.7	2.8	84.2	15.6
Canada	64.5	35.1	118.1	79.8
United Kingdom	15.8	47.4	29.6	66.5
Ecuador	3.8	.8	6.7	6.3
Malaysia	10.6	(5.3)	6.6	(10.8)
Other International	(2.6)	(.5)	(4.2)	(1.4)
Total	$139.8	80.3	241.0	156.0

Exploration and production operations in the United States reported earnings of $47.7 million in the second quarter of 2004 compared to earnings of $2.8 million a year ago. This improvement was primarily due to higher oil and natural gas sales prices coupled with higher sales volumes due to the 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. Exploration expenses were $10.3 million lower in the 2004 period compared to 2003 primarily due to less dry holes expense.

Results of Operations (Contd.)

<u>*Exploration and Production*</u> (Contd.)

Continuing operations in Canada earned $64.5 million this quarter compared to $35.1 million a year ago. This increase was the result of higher crude oil and natural gas sales prices and higher crude oil sales volumes, but was partially offset by lower natural gas production volumes. Production expenses associated with synthetic crude oil volumes increased $2.9 million in the current period due to higher natural gas costs and increased repairs.

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 $166.7 million. The operating results of those sold assets have also been reported as discontinued operations for all periods presented.

U.K. operations earned $15.8 million in the current quarter, down from $47.4 million from the prior year. The 2003 period included a $34 million after-tax gain on sale of the Ninian and Columba fields. Higher crude oil sales prices in 2004 more than offset earnings in the 2003 period from the Ninian and Columba fields, which were sold in May 2003.

Operations in Ecuador earned $3.8 million in the second quarter of 2004 compared to $.8 million a year ago. The improvement was the result of higher sales prices and sales volumes in the 2004 period. Higher sales volumes were attributable to start-up of a new third-party owned heavy oil pipeline in late 2003. Production expenses and depreciation expense increased in the 2004 period due to higher sales volumes. Income tax expense was $1.9 million in 2004, but there was no income tax expense in 2003.

Operations in Malaysia reported earnings of $10.6 million in the 2004 period compared to a loss of $5.3 million during the same period in 2003. The improvement in Malaysia was primarily due to crude oil sales from the West Patricia field partially offset by increased dry hole expenses. There were no crude oil sales at the West Patricia field during the 2003 period.

Other international operations reported a loss of $2.6 million in the second quarter of 2004 compared to a loss of $.5 million in the comparable period a year ago. Lower revenues from natural gas storage facilities and higher geological and geophysical costs in the Congo were the primary causes of the higher loss in the 2004 period.

Operations in the United States for the six months ended June 30, 2004 produced income of $84.2 million compared to income of $15.6 million in 2003. The improvement was primarily due to higher oil and natural gas sales prices and sales volumes, 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 deepwater Gulf of Mexico. Also contributing to the improved results in 2004 were $15.4 million in after-tax gains on disposal of several minor natural gas properties onshore United States.

In the first half of 2004, Canadian continuing operations earned $118.1 million compared to $79.8 million a year ago. Higher sales prices for oil and natural gas and higher sales volumes of crude oil were partially offset by lower natural gas sales volumes. Production expenses for synthetic oil operations increased $8.2 million in the current period primarily due to higher repairs and natural gas costs.

Income in the U.K. for the six-month period ended June 30, 2004 was $29.6 million compared to $66.5 million a year ago. The decrease was due to the $34 million after-tax gain on sale of Ninian and Columba in 2003 and lower sales volumes of crude oil in the 2004 period, partially offset by higher sales prices in the latter period.

For the first six months of 2004, earnings in Ecuador were $6.7 million compared to $6.3 million for the 2003 period. Higher crude oil sales volumes in the first half of 2004 were mostly offset by higher production, depreciation and income tax expenses.

Malaysia operations earned $6.6 million in the first half of 2004 compared to a loss of $10.8 million a year ago. The improvement in 2004 earnings was primarily due to crude oil sales from the West Patricia field partially offset by increased dry hole expenses. No crude oil sales occurred at the West Patricia field during the 2003 period.

Other international operations reported a loss of $4.2 million in the first six months of 2004 compared to a loss of $1.4 million in the 2003 period. Lower gas storage revenue and higher exploration expenses and administrative costs were the primary causes of the increased loss.

Results of Operations (Contd.)

Exploration and Production (Contd.)

On a worldwide basis, the Company's crude oil and condensate prices averaged $34.14 per barrel in the second quarter 2004 compared to $24.60 in the 2003 period. Average crude oil and liquids production from continuing operations was 97,375 barrels per day compared to 75,624 barrels per day in the second quarter of 2003, with the increase primarily attributable to production at the Medusa and Habanero fields in deepwater Gulf of Mexico, both of which commenced production in the fourth quarter of 2003, and higher volumes at the West Patricia field in Malaysia due to a full quarter of production in 2004. Production at the West Patricia field commenced in May 2003. Oil sales volumes from continuing operations averaged 99,819 barrels per day in the second quarter 2004 compared to 67,452 barrels per day in the 2003 period. North American natural gas sales prices averaged $6.22 per MCF in the second quarter 2004 compared to $5.22 per MCF in the same quarter of 2003. Total natural gas sales volumes from continuing operations averaged 123 million cubic feet a day in the second quarter 2004, up 11 million cubic feet per day from the 2003 quarter primarily due to production from the Medusa and Habanero fields in the deepwater Gulf of Mexico. The Company hedged the sales prices of a portion of its oil and natural gas production in 2003. In the second quarter of 2003, these hedges reduced the average realized worldwide crude oil and North American natural gas sales prices by $1.54 per barrel and $.22 per MCF, respectively.

For the first six months of 2004, the Company's sales price for crude oil and condensate averaged $32.58 per barrel compared to $26.28 per barrel in 2003. Crude oil and condensate production from continuing operations in the first half of 2004 averaged 96,255 barrels per day compared to 71,722 barrels per day a year ago. The increase was mostly attributable to start-up of Medusa and Habanero in late 2003 and a full six months production from the West Patricia field in shallow-water Malaysia. Average sales prices for North American natural gas in the first six months of 2004 was $6.05 per MCF, up from $5.58 in 2003. Total natural gas sales volume from continuing operations increased by 9% and averaged 124 million cubic feet per day in the 2004 period, with the increase resulting from production at the Medusa and Habanero fields in the deepwater Gulf of Mexico. The Company's 2003 hedging program reduced the average realized worldwide crude oil and North American natural gas sales prices in the first six months of 2003 by $2.39 per barrel and $.35 per MCF, respectively.

The tables on pages 18 and 19 provide additional details of the results of exploration and production operations for the second quarter and first six months of 2004 and 2003.

Results of Operations (Contd.)

Exploration and Production (Contd.)

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

	Three Months Ended June 30,		Six Months Ended June 30,	
	2004	2003	2004	2003
Net crude oil, condensate and gas liquids produced – barrels per day	102,384	82,488	102,408	78,740
Continuing operations	97,375	75,624	96,255	71,722
United States	23,230	4,019	20,968	3,654
Canada – light	680	1,554	706	1,582
– heavy	4,654	4,036	4,518	3,987
– offshore	27,911	30,743	28,396	29,276
– synthetic	11,353	10,431	11,940	9,890
United Kingdom	12,225	16,872	11,953	17,651
Malaysia	9,591	4,875	10,006	2,451
Ecuador	7,731	3,094	7,768	3,231
Discontinued operations	5,009	6,864	6,153	7,018
Net crude oil, condensate and gas liquids sold – barrels per day	104,828	74,316	103,153	76,262
Continuing operations	99,819	67,452	97,000	69,244
United States	23,230	4,049	20,968	3,654
Canada – light	680	1,554	706	1,582
– heavy	4,654	4,036	4,518	3,987
– offshore	28,687	27,926	29,587	28,861
– synthetic	11,353	10,431	11,940	9,890
United Kingdom	12,864	16,771	12,271	17,687
Malaysia	12,569	—	10,307	—
Ecuador	5,782	2,685	6,703	3,583
Discontinued operations	5,009	6,864	6,153	7,018
Net natural gas sold – thousands of cubic feet per day	160,747	231,057	186,651	229,619
Continuing operations	123,025	111,992	123,593	113,851
United States	103,673	83,553	101,094	80,771
Canada	14,637	20,798	14,601	23,452
United Kingdom	4,715	7,641	7,898	9,628
Discontinued operations	37,722	119,065	63,058	115,768
Total net hydrocarbons produced – equivalent barrels per day (1)	129,175	120,698	133,517	117,010
Total net hydrocarbons sold – equivalent barrels per day (1)	131,619	112,526	134,262	114,532
Total net hydrocarbons produced from continuing operations – equivalent barrels per day (1)	117,879	94,289	116,854	90,697
Total net hydrocarbons sold from continuing operations – equivalent barrels per day (1)	120,323	86,117	117,599	88,219
Weighted average sales prices – Continuing operations				
Crude oil and condensate – dollars per barrel (2)				
United States (4)	$ 33.60	24.69	32.78	24.73
Canada (3) – light	36.08	27.66	34.77	28.60
– heavy (4)	20.08	12.64	18.41	12.52
– offshore (4)	35.13	24.80	33.28	26.50
– synthetic (4)	37.65	26.67	36.03	26.18
United Kingdom	34.53	26.46	33.13	29.60
Malaysia	38.21	—	36.88	—
Ecuador	25.97	19.68	24.67	24.79
Natural gas – dollars per thousand cubic feet				
United States (2) (4)	$ 6.33	5.26	6.15	5.76
Canada (3) (4)	5.43	5.08	5.36	4.98
United Kingdom (3)	3.09	3.18	4.24	3.38

(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 six-month 2003 prices include the effects of the Company's 2003 hedging program.

ITEM 2. MANAGEMENT'S DISCUSSION AND ANALYSIS (Contd.)

CONTINUING OIL AND GAS OPERATING RESULTS (unaudited)

(Millions of dollars)	United States	Canada	United Kingdom	Ecuador	Malaysia	Other	Synthetic Oil – Canada	Total
Three Months Ended June 30, 2004								
Oil and gas sales and other revenues	$ 131.7	109.6	41.7	13.7	43.9	.6	38.9	380.1
Production expenses	21.0	9.0	5.3	5.6	8.4	—	17.8	67.1
Depreciation, depletion and amortization	19.1	23.4	8.2	2.2	8.1	—	2.6	63.6
Accretion of asset retirement obligations	.9	.6	.7	—	—	.1	.1	2.4
Exploration expenses								
Dry holes	4.5	(.1)	—	—	4.1	—	—	8.5
Geological and geophysical	2.6	.5	—	—	2.9	.5	—	6.5
Other	2.8	1.4	.2	—	—	.1	—	4.5
	9.9	1.8	.2	—	7.0	.6	—	19.5
Undeveloped lease amortization	3.1	.6	—	—	—	—	—	3.7
Total exploration expenses	13.0	2.4	.2	—	7.0	.6	—	23.2
Selling and general expenses	4.3	3.3	.7	.2	1.1	2.1	.1	11.8
Income tax provisions	25.7	21.0	10.8	1.9	8.7	.4	3.7	72.2
Results of operations (excluding corporate overhead and interest)	$ 47.7	49.9	15.8	3.8	10.6	(2.6)	14.6	139.8
Three Months Ended June 30, 2003								
Oil and gas sales and other revenues	$ 49.9	79.1	91.4	4.8	—	1.6	25.4	252.2
Production expenses	8.9	9.0	9.3	2.8	—	—	14.9	44.9
Depreciation, depletion and amortization	9.2	23.6	8.4	1.1	.3	—	2.3	44.9
Accretion of asset retirement obligations	.8	.7	.8	—	.1	.1	.1	2.6
Exploration expenses								
Dry holes	16.5	—	—	—	—	(.1)	—	16.4
Geological and geophysical	2.2	(.1)	—	—	3.1	—	—	5.2
Other	1.8	.3	.3	—	. 5	—	—	2.9
	20.5	.2	.3	—	3.6	(.1)	—	24.5
Undeveloped lease amortization	2.8	.8	—	—	—	—	—	3.6
Total exploration expenses	23.3	1.0	.3	—	3.6	(.1)	—	28.1
Selling and general expenses	3.3	2.7	.5	.1	1.3	1.6	.2	9.7
Income tax provisions	1.6	12.3	24.7	—	—	.5	2.6	41.7
Results of operations (excluding corporate overhead and interest)	$ 2.8	29.8	47.4	.8	(5.3)	(.5)	5.3	80.3
Six Months Ended June 30, 2004								
Oil and gas sales and other revenues	$ 263.0	212.7	80.1	30.1	69.5	1.6	78.3	735.3
Production expenses	38.9	18.2	11.7	13.5	11.1	—	37.5	130.9
Depreciation, depletion and amortization	36.0	49.3	15.5	5.1	13.4	—	5.3	124.6
Accretion of asset retirement obligations	1.8	1.3	1.4		.1	.2	.2	5.0
Exploration expenses								
Dry holes	33.1	(.1)	—	—	17.5	.1	—	50.6
Geological and geophysical	3.9	1.2	—	—	3.0	.7	—	8.8
Other	3.2	1.6	.3	—	—	.2	—	5.3
	40.2	2.7	.3	—	20.5	1.0	—	64.7
Undeveloped lease amortization	6.4	1.2	—	—	—	—	—	7.6
Total exploration expenses	46.6	3.9	.3	—	20.5	1.0	—	72.3
Selling and general expenses	10.1	5.7	1.5	.3	2.4	4.3	.3	24.6
Income tax provisions	45.4	41.9	20.1	4.5	15.4	.3	9.3	136.9
Results of operations (excluding corporate overhead and interest)	$ 84.2	92.4	29.6	6.7	6.6	(4.2)	25.7	241.0
Six Months Ended June 30, 2003								
Oil and gas sales and other revenues	$ 100.6	175.1	149.6	16.1	—	2.3	46.9	490.6
Production expenses	16.7	17.2	20.8	7.0	—	—	29.3	91.0
Depreciation, depletion and amortization	17.5	45.3	18.0	2.6	.5	.1	4.3	88.3
Accretion of asset retirement obligations	1.6	1.2	1.7	—	.1	.2	.2	5.0

Exploration expenses								
Dry holes	19.4	—	—	—	—	(.1)	—	19.3
Geological and geophysical	5.8	.2	—	—	7.5	—	—	13.5
Other	2.3	.4	.4	—	.5	.1	—	3.7
	27.5	.6	.4	—	8.0	—	—	36.5
Undeveloped lease amortization	5.4	1.6	—	—	—	—	—	7.0
Total exploration expenses	32.9	2.2	.4	—	8.0	—	—	43.5
Selling and general expenses	7.9	4.9	1.6	.2	2.2	3.2	.3	20.3
Income tax provisions	8.4	33.1	40.6	—	—	.2	4.2	86.5
Results of operations (excluding corporate overhead and interest)	$ 15.6	71.2	66.5	6.3	(10.8)	(1.4)	8.6	156.0

ITEM 2. MANAGEMENT'S DISCUSSION AND ANALYSIS (Contd.)

Results of Operations (Contd.)

Refining and Marketing

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

(Millions of dollars)	Income (Loss) Three Months Ended June 30, 2004	2003	Six Months Ended June 30, 2004	2003
Refining and marketing				
North America	$27.4	(1.5)	16.9	(7.9)
United Kingdom	12.1	1.8	16.2	4.7
Total	$39.5	.3	33.1	(3.2)

Refining and marketing operations in North America generated a profit of $27.4 million during the second quarter of 2004 compared to a loss of $1.5 million in the same period a year ago. The 2003 period included $12.3 million in after-tax costs relating to a fire at the Company's Meraux, Louisiana refinery. The Company's North American refining and marketing margins were significantly higher in the current quarter compared to margins in the same quarter of 2003. Earnings in the United Kingdom were $12.1 million in the second quarter of 2004, an increase of $10.3 million over the same period a year ago, with the higher earnings in 2004 resulting from significantly improved margins. Worldwide petroleum product sales averaged 347,972 barrels per day in 2004, a 27% increase from the second quarter of 2003. Worldwide refinery inputs were 181,700 barrels per day in the second quarter of 2004 compared to 137,749 in the 2003 quarter; inputs in 2003 were adversely affected by the Meraux refinery fire.

Refining and marketing operations in North America in the first half of 2004 had earnings of $16.9 million compared to a loss of $7.9 million in the 2003 period, which included the net after-tax costs associated with the Meraux refinery fire. North American refining and marketing margins improved significantly in the current period compared to a year ago. The 2004 period also included a net after-tax gain of $3 million from sale of the Company's jointly owned terminals in the U.S. Results in the United Kingdom reflected earnings of $16.2 million in the six months ended June 30, 2004 compared to a profit of $4.7 million in 2003 due to higher margins compared to the same period a year ago.

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

	Three Months Ended June 30, 2004	2003	Six Months Ended June 30, 2004	2003
Refinery inputs – barrels per day	181,700	137,749	176,375	149,280
North America	142,773	103,017	138,985	113,838
United Kingdom	38,927	34,732	37,390	35,442
Petroleum products sold – barrels per day	347,972	274,034	324,841	251,276
North America	308,412	237,809	287,517	216,866
Gasoline	218,724	166,603	201,098	148,646
Kerosine	578	5,540	4,443	6,747
Diesel and home heating oils	65,903	44,759	62,213	41,242
Residuals	12,501	12,784	12,789	13,598
Asphalt, LPG and other	10,706	8,123	6,974	6,633
United Kingdom	39,560	36,225	37,324	34,410
Gasoline	13,027	11,478	12,750	10,744
Kerosine	1,787	2,890	2,541	2,718
Diesel and home heating oils	16,058	14,483	14,501	13,834
Residuals	4,718	3,109	4,430	3,806
LPG and other	3,970	4,265	3,102	3,308

Results of Operations (Contd.)

Corporate and other

The net cost of corporate activities, which include interest income and expense and corporate overhead not allocated to operating functions, was $11.2 million in the current quarter compared to $8.3 million in the 2003 quarter. In the first six months of 2004, corporate activities reflected a net cost of $25.3 million compared to a net profit of $2.4 million a year ago. The six-month 2003 results included a $20.1 million gain from resolution of prior years' tax matters. Excluding the tax resolution benefit, higher costs in the second quarter and first six months of 2004 compared to the comparable 2003 periods were attributable to higher administrative expenses and a lower portion of interest costs being capitalized, partially offset by more interest income earned on higher cash balances.

Financial Condition

Net cash provided by continuing operating activities was $494.9 million for the first six months of 2004 compared to $249.2 million for the same period in 2003. The improvement in 2004 was attributable to an increase in revenues due to higher oil, natural gas and product prices that exceeded the increase in cash costs for products sold and operating and administrative expenses. Changes in operating working capital other than cash and cash equivalents used cash of $1.8 million in the first six months of 2004 but provided cash of $6.1 million in the first six months of 2003. Cash from operating activities was reduced by expenditures for major repairs and asset retirement obligations totaling $9 million in 2004 and $26.2 million in 2003. Proceeds from the sale of assets, excluding discontinued operations, provided cash of $40.7 million in the first six months of 2004 compared to $69 million in the same period in 2003.

Other predominant uses of cash in each year were for dividends, which totaled $36.8 million in 2004 and $36.7 million in 2003 and for capital expenditures, which including amounts expensed, are summarized in the following table.

	Six Months Ended June 30,	
(Millions of dollars)	**2004**	**2003**
Capital Expenditures – continuing operations		
Exploration and production	$340.6	324.5
Refining and marketing	71.0	109.4
Corporate and other	.6	.6
Total capital expenditures – continuing operations	412.2	434.5
Geological, geophysical and other exploration expenses charged to income	(14.1)	(17.2)
Total property additions and dry holes – continuing operations	$398.1	417.3

Working capital at June 30, 2004 was $876.2 million, up $647.7 million from December 31, 2003, with the increase primarily due to the proceeds from sales of most Western Canadian conventional oil and natural gas assets in the second quarter 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 $205.4 million below current costs at June 30, 2004.

At June 30, 2004, long-term notes payable of $1,032.8 million were down $28.6 million from December 31, 2003 due to payments of amounts drawn under the Company's long-term revolving credit agreements. Long-term nonrecourse debt of a subsidiary was $14 million, down $14.9 million from December 31, 2003, primarily due to repayments. A summary of capital employed at June 30, 2004 and December 31, 2003 follows.

(Millions of dollars)	**June 30, 2004**		**Dec. 31, 2003**	
	Amount	**%**	**Amount**	**%**
Capital Employed				
Notes payable	$ 1,032.8	30.4	$1,061.4	34.9
Nonrecourse debt of a subsidiary	14.0	.4	28.9	1.0
Stockholders' equity	2,350.6	69.2	1,950.9	64.1
Total capital employed	$ 3,397.4	100.0	$3,041.2	100.0

Accounting and Other Matters *(Contd.)*

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. The FASB is considering whether an oil and gas company's investment in mineral leases should be classified as intangible assets. SFAS No. 141 and SFAS No. 142 established new accounting guidelines for both finite lived intangible assets and indefinite lived intangible assets. Under SFAS No. 141 and SFAS No. 142, intangible assets should be separately reported on the Balance Sheet, with accompanying disclosures in the notes to the financial statements. SFAS No. 142 does not change the accounting prescribed in SFAS No. 19, Financial Accounting and Reporting by Oil and Gas Producing Companies, and is silent about whether its disclosure provisions apply to oil and gas companies. The Company does not believe that SFAS No. 141 and SFAS No. 142 change the classification and disclosure of oil and gas mineral leases and it continues to classify these assets as part of Property, Plant and Equipment in the Consolidated Balance Sheet and does not provide the additional disclosures for these assets. The FASB has issued a proposed 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. Should the FASB proposed staff position not be adopted and it is determined that oil and gas mineral leases are intangible assets in accordance with SFAS No. 141 and SFAS No. 142, the Company would reclassify $112 million and $143 million as intangible undeveloped mineral interests at June 30, 2004 and December 31, 2003, respectively. In addition, a reclassification of $5 million and $8 million would be made as intangible developed mineral interests at June 30, 2004 and December 31, 2003, respectively. Both intangible assets would be presented net of accumulated amortization. Historically, undeveloped mineral leases have been amortized over the life of the lease period, while developed mineral leases have been amortized using the units of production method over the expected life of proved reserves. The amounts included herein are based on our understanding of the issue on the EITF's agenda. If all mineral leases associated with oil and gas properties are deemed to be intangible assets in accordance with SFAS No. 141 and SFAS No. 142 by the EITF:

- These assets would not be included in Property, Plant and Equipment on our Consolidated Balance Sheet
- We do not believe that our net income or cash flows from operations would be materially affected because the amortization of these assets would not be different than the method currently used by the Company
- Disclosures required by SFAS No. 141 and SFAS No. 142 relative to intangible assets would be included in the notes to the financial statements.

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 arbiters 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 June 30, 2004, the Company has a receivable of approximately $10.2 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 July 2004. Production is expected to average approximately 114,000 barrels of oil equivalent per day in the third quarter 2004. The Front Runner field, in the deepwater Gulf of Mexico, is expected to start up production in the fourth quarter 2004. 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, must also approve the Kikeh development plan. The development plan calls for first production in late 2007. North American gasoline marketing margins have weakened early in the third quarter 2004 compared to the just completed second quarter. The Company currently anticipates total capital expenditures in 2004 of approximately $950 million.

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 June 30, 2004 with notional amounts totaling $30 million that were designed to hedge fluctuations in cash flows of a similar amount of variable-rate debt. These swaps mature in July and October 2004. The swaps require the Company to pay an average interest rate of 6.06% over their composite lives, and at June 30, 2004, the interest rate to be received by the Company averaged 1.16%. The variable interest rate received by the Company under each swap contract is repriced quarterly. The Company considers these swaps to be a hedge against potentially higher future interest rates. The estimated fair value of these interest rate swaps was recorded as a liability of $.5 million at June 30, 2004, with the offsetting loss recorded in Accumulated Other Comprehensive Income (AOCI) in Stockholders' Equity.

At June 30, 2004, 39% of the Company's debt had variable interest rates. Based on debt outstanding at June 30, 2004, a 10% increase in variable interest rates would increase the Company's interest expense approximately $1.4 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 June 30, 2004 for a remaining notional volume of 5.7 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 from July 1, 2004 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 June 30, 2004, the estimated fair value of these agreements was recorded as an asset of $18.4 million. A 10% increase in the average NYMEX price of natural gas would have increased this asset by $3.4 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 June 30, 2004 for a total remaining notional volume of 2.4 million MMBTU that effectively fixed the settlement price for the natural gas purchase swaps maturing in July through 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 June 30, 2004 the estimated fair value of these agreements was recorded as a liability of $2.4 million. A 10% increase in the average NYMEX index price of natural gas would have increased this liability by $1.5 million, while a 10% decrease would have reduced this liability by a similar amount.

At June 30, 2004, the Company was a party to natural gas put options covering 3.1 million MMBTU in future natural gas sales during July through 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 June 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.

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 second quarter of 2004 that have materially affected, or are reasonable 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. The Company believes that the counterclaim is without merit and that the amount of damages sought is frivolous. Trial will likely begin in January 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.

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 4. SUBMISSION OF MATTERS TO A VOTE OF SECURITY HOLDERS

At the annual meeting of security holders on May 12, 2004, the directors proposed by management were elected with a tabulation of votes to the nearest share as shown below.

	For	Withheld
Frank W. Blue	84,008,449	1,271,291
George S. Dembroski	84,006,801	1,272,939
Claiborne P. Deming	84,692,292	587,448
Robert A. Hermes	85,035,385	244,355
R. Madison Murphy	58,852,367	26,427,373
William C. Nolan Jr.	84,459,283	820,457
Ivar B. Ramberg	84,911,641	368,099
David J. H. Smith	85,031,830	247,910
Caroline G. Theus	84,700,073	579,667

The earlier appointment by the Audit Committee of the Board of Directors of KPMG LLP as independent auditors for 2004 was approved, with 83,766,707 shares voted in favor, 1,495,931 shares voted in opposition and 17,102 shares not voted.

ITEM 6. EXHIBITS AND REPORTS ON FORM 8-K

(a) The Exhibit Index on page 27 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 April 29, 2004 that included a News Release announcing the Company’s earnings and certain other financial information for the three-month period ended March 31, 2004.

(c) A report on Form 8-K was filed on April 12, 2004 that included a News Release announcing the Company’s expected results of operations for the three-month period ended March 31, 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)

August 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)

	Six Months Ended June 30, 2004	Year Ended December 31, 2003	2002	2001	2000	1999
Income from continuing operations before income taxes	$ 397,443	374,205	122,067	437,342	406,086	153,185
Distributions (less than) greater than equity in earnings of affiliates	(2,541)	(209)	(3)	(365)	(34)	64
Previously capitalized interest charged to earnings during period	7,412	10,457	7,748	3,450	3,507	3,146
Interest and expense on indebtedness, excluding capitalized interest	19,401	20,511	26,968	19,006	16,337	20,274
Interest portion of rentals*	4,271	9,857	9,445	7,953	5,808	3,267
Earnings before provision for taxes and fixed charges	**$ 425,986**	**414,821**	**166,225**	**467,386**	**431,704**	**179,936**
Interest and expense on indebtedness, excluding capitalized interest	19,401	20,511	26,968	19,006	16,337	20,274
Capitalized interest	9,066	37,240	24,536	20,283	13,599	7,865
Interest portion of rentals*	4,271	9,857	9,445	7,953	5,808	3,267
Total fixed charges	**$ 32,738**	**67,608**	**60,949**	**47,242**	**35,744**	**31,406**
Ratio of earnings to fixed charges	**13.0**	**6.1**	**2.7**	**9.9**	**12.1**	**5.7**

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

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: August 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: August 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 June 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.

August 5, 2004

/s/ Claiborne P. Deming

Claiborne P. Deming
Principal Executive Officer

/s/ Steven A. Cossé

Steven A. Cossé
Principal Financial Officer