MURPHY OIL CORP /DE
Form 10-Q
August 05, 2011
**Table of Contents**

# UNITED STATES

# SECURITIES AND EXCHANGE COMMISSION

**Washington, D.C. 20549**

# FORM 10-Q

**(Mark one)**

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

**For the quarterly period ended June 30, 2011**

**OR**

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

**For the transition period from to**

**Commission File Number 1-8590**

# MURPHY OIL CORPORATION

**(Exact name of registrant as specified in its charter)**

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

**(870) 862-6411**

**(Registrant s telephone number, including area code)**

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. þ Yes ¨ No

Indicate by check mark whether the registrant has submitted electronically and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T (§232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files). þ Yes ¨ No

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, or a smaller reporting company. See the definitions of large accelerated filer, accelerated filer and smaller reporting company in Rule 12b-2 of the Exchange act.

| | | | |
|---|---|---|---|
| Large accelerated filer | þ | Accelerated filer | ¨ |
| Non-accelerated filer | ¨ | Smaller reporting company | ¨ |

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Exchange Act). ¨ Yes þ No

Number of shares of Common Stock, $1.00 par value, outstanding at June 30, 2011 was **193,512,972**.

Table of Contents

**MURPHY OIL CORPORATION**

**TABLE OF CONTENTS**

**Table of Contents**

**PART I FINANCIAL INFORMATION**

***ITEM 1. FINANCIAL STATEMENTS***

Murphy Oil Corporation and Consolidated Subsidiaries

**CONSOLIDATED BALANCE SHEETS**

(Thousands of dollars)

| | (Unaudited) June 30, 2011 | December 31, 2010 |
|---|---|---|
| **ASSETS** | | |
| Current assets | | |
| Cash and cash equivalents | $ 801,246 | 535,825 |
| Canadian government securities with maturities greater than 90 days at the date of acquisition | 538,082 | 616,558 |
| Accounts receivable, less allowance for doubtful accounts of $7,970 in 2011 and $7,954 in 2010 | 1,756,713 | 1,467,311 |
| Inventories, at lower of cost or market | | |
| Crude oil and blend stocks | 258,063 | 147,256 |
| Finished products | 420,571 | 388,162 |
| Materials and supplies | 234,704 | 226,795 |
| Prepaid expenses | 126,160 | 88,241 |
| Deferred income taxes | 77,978 | 80,545 |
| Total current assets | 4,213,517 | 3,550,693 |
| Property, plant and equipment, at cost less accumulated depreciation, depletion and amortization of $6,741,946 in 2011 and $6,040,996 in 2010 | 11,062,349 | 10,367,847 |
| Goodwill | 44,390 | 42,850 |
| Deferred charges and other assets | 246,780 | 271,853 |
| Total assets | $ 15,567,036 | 14,233,243 |
| **LIABILITIES AND STOCKHOLDERS EQUITY** | | |
| Current liabilities | | |
| Current maturities of long-term debt | $ 349,946 | 41 |
| Accounts payable and accrued liabilities | 2,600,956 | 2,572,105 |
| Income taxes payable | 392,166 | 358,764 |
| Total current liabilities | 3,343,068 | 2,930,910 |
| Long-term debt | 1,184,529 | 939,350 |
| Deferred income taxes | 1,244,882 | 1,212,213 |
| Asset retirement obligations | 576,513 | 555,248 |
| Deferred credits and other liabilities | 388,878 | 395,972 |
| Stockholders equity | | |
| Cumulative Preferred Stock, par $100, authorized 400,000 shares, none issued | 0 | 0 |
| Common Stock, par $1.00, authorized 450,000,000 shares, issued 193,714,102 shares in 2011 and 193,293,526 shares in 2010 | 193,714 | 193,294 |
| Capital in excess of par value | 788,673 | 767,762 |
| Retained earnings | 7,275,196 | 6,800,992 |
| Accumulated other comprehensive income | 576,826 | 449,428 |

| | | |
|---|---|---|
| Treasury stock, 201,130 shares of Common Stock in 2011 and 457,518 shares of Common Stock in 2010, at cost | (5,243) | (11,926) |
| Total stockholders equity | 8,829,166 | 8,199,550 |
| Total liabilities and stockholders equity | $ 15,567,036 | 14,233,243 |

See Notes to Consolidated Financial Statements, page 7.

**Table of Contents**

Murphy Oil Corporation and Consolidated Subsidiaries

**CONSOLIDATED STATEMENTS OF INCOME (unaudited)**

(Thousands of dollars, except per share amounts)

| | Three Months Ended June 30, | | Six Months Ended June 30, | |
|---|---|---|---|---|
| | 2011 | 2010 | 2011 | 2010 |
| **REVENUES** | | | | |
| Sales and other operating revenues | $ 8,690,140 | 5,592,353 | 16,036,143 | 10,821,028 |
| Gain on sale of assets | 23,079 | 113 | 23,132 | 789 |
| Interest and other income (expense) | 8,272 | (535) | 13,883 | (49,726) |
| Total revenues | 8,721,491 | 5,591,931 | 16,073,158 | 10,772,091 |
| **COSTS AND EXPENSES** | | | | |
| Crude oil and product purchases | 7,068,906 | 4,253,167 | 12,948,722 | 8,232,126 |
| Operating expenses | 600,918 | 460,244 | 1,153,902 | 925,851 |
| Exploration expenses, including undeveloped lease amortization | 122,538 | 53,093 | 218,812 | 119,457 |
| Selling and general expenses | 86,033 | 68,851 | 161,500 | 133,982 |
| Depreciation, depletion and amortization | 270,816 | 288,212 | 548,156 | 580,892 |
| Accretion of asset retirement obligations | 9,658 | 7,844 | 19,145 | 15,457 |
| Redetermination of Terra Nova working interest | 0 | 5,346 | (5,351) | 10,862 |
| Interest expense | 12,600 | 13,893 | 24,319 | 28,702 |
| Interest capitalized | (2,639) | (3,696) | (9,072) | (6,361) |
| Total costs and expenses | 8,168,830 | 5,146,954 | 15,060,133 | 10,040,968 |
| Income before income taxes | 552,661 | 444,977 | 1,013,025 | 731,123 |
| Income tax expense | 241,048 | 172,688 | 432,509 | 309,943 |
| **NET INCOME** | $ 311,613 | 272,289 | 580,516 | 421,180 |
| **NET INCOME PER COMMON SHARE** | | | | |
| Basic | $ 1.61 | 1.42 | 3.00 | 2.20 |
| Diluted | 1.60 | 1.41 | 2.98 | 2.18 |
| Average common shares outstanding | | | | |
| Basic | 193,481,601 | 191,585,996 | 193,267,154 | 191,394,728 |
| Diluted | 194,916,194 | 193,169,099 | 194,642,191 | 192,821,487 |

See Notes to Consolidated Financial Statements, page 7.

The Exhibit Index is on page 33.

**Table of Contents**

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, | |
|---|---|---|---|---|
| | 2011 | 2010 | 2011 | 2010 |
| Net income | $ 311,613 | 272,289 | 580,516 | 421,180 |
| Other comprehensive income (loss), net of tax | | | | |
| Net gain (loss) from foreign currency translation | 23,371 | (132,045) | 123,025 | (40,385) |
| Retirement and postretirement benefit plan adjustments | 2,216 | 2,333 | 4,373 | 4,527 |
| **COMPREHENSIVE INCOME** | $ 337,200 | 142,577 | 707,914 | 385,322 |

See Notes to Consolidated Financial Statements, page 7.

*4*

**Table of Contents**

Murphy Oil Corporation and Consolidated Subsidiaries

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

(Thousands of dollars)

| | Six Months Ended June 30, 2011 | Six Months Ended June 30, 2010 |
|---|---|---|
| **OPERATING ACTIVITIES** | | |
| Net income | $ 580,516 | 421,180 |
| Adjustments to reconcile net income to net cash provided by operating activities | | |
| Depreciation, depletion and amortization | 548,156 | 580,892 |
| Amortization of deferred major repair costs | 23,520 | 16,150 |
| Expenditures for asset retirements | (16,441) | (25,280) |
| Dry hole costs | 105,307 | 29,841 |
| Amortization of undeveloped leases | 60,530 | 48,378 |
| Accretion of asset retirement obligations | 19,145 | 15,457 |
| Deferred and noncurrent income tax charges | 6,220 | 33,233 |
| Pretax gain from disposition of assets | (23,132) | (789) |
| Net decrease (increase) in noncash operating working capital | (455,655) | 249,780 |
| Other operating activities, net | 69,776 | 78,901 |
| Net cash provided by operating activities | 917,942 | 1,447,743 |
| **INVESTING ACTIVITIES** | | |
| Property additions and dry hole costs | (1,258,731) | (992,256) |
| Proceeds from sales of assets | 27,538 | 1,792 |
| Purchase of investment securities* | (675,606) | (1,263,026) |
| Proceeds from maturity of investment securities* | 754,082 | 1,239,290 |
| Expenditures for major repairs | (680) | (89,102) |
| Other net | 6,753 | (23,110) |
| Net cash required by investing activities | (1,146,644) | (1,126,412) |
| **FINANCING ACTIVITIES** | | |
| Borrowings (repayments) of notes payable | 594,980 | (122,019) |
| Repayment of nonrecourse debt of a subsidiary | 0 | (2,269) |
| Proceeds from exercise of stock options and employee stock purchase plans | 7,900 | 14,798 |
| Excess tax benefits related to exercise of stock options | 4,068 | 483 |
| Withholding tax on stock-based incentive awards | (8,014) | (5,170) |
| Issue cost of debt facility | (7,672) | 0 |
| Cash dividends paid | (106,312) | (95,700) |
| Net cash provided (required) by financing activities | 484,950 | (209,877) |
| Effect of exchange rate changes on cash and cash equivalents | 9,173 | (13,778) |
| Net increase in cash and cash equivalents | 265,421 | 97,676 |
| Cash and cash equivalents at January 1 | 535,825 | 301,144 |

| | | | |
|---|---|---|---|
| Cash and cash equivalents at June 30 | $ | 801,246 | 398,820 |

* Investments are Canadian government securities with maturities greater than 90 days at the date of acquisition.

See Notes to Consolidated Financial Statements, page 7.

*5*

Table of Contents

Murphy Oil Corporation and Consolidated Subsidiaries

**CONSOLIDATED STATEMENTS OF STOCKHOLDERS EQUITY (unaudited)**

(Thousands of dollars)

| | Six Months Ended June 30, 2011 | 2010 |
|---|---|---|
| **Cumulative Preferred Stock** par $100, authorized 400,000 shares, none issued | 0 | 0 |
| **Common Stock** par $1.00, authorized 450,000,000 shares, issued 193,714,102 shares at June 30, 2011 and 192,280,606 shares at June 30, 2010 | | |
| Balance at beginning of period | $ 193,294 | 191,798 |
| Exercise of stock options | 420 | 483 |
| Balance at end of period | 193,714 | 192,281 |
| **Capital in Excess of Par Value** | | |
| Balance at beginning of period | 767,762 | 680,509 |
| Exercise of stock options, including income tax benefits | 13,591 | 14,668 |
| Restricted stock transactions and other | (15,119) | (9,688) |
| Stock-based compensation | 21,661 | 20,299 |
| Sale of stock under employee stock purchase plans | 778 | 477 |
| Balance at end of period | 788,673 | 706,265 |
| **Retained Earnings** | | |
| Balance at beginning of period | 6,800,992 | 6,204,316 |
| Net income for the period | 580,516 | 421,180 |
| Cash dividends | (106,312) | (95,700) |
| Balance at end of period | 7,275,196 | 6,529,796 |
| **Accumulated Other Comprehensive Income** | | |
| Balance at beginning of period | 449,428 | 287,187 |
| Foreign currency translation gains (losses), net of income taxes | 123,025 | (40,385) |
| Retirement and postretirement benefit plan adjustments, net of income taxes | 4,373 | 4,527 |
| Balance at end of period | 576,826 | 251,329 |
| **Treasury Stock** | | |
| Balance at beginning of period | (11,926) | (17,784) |
| Sale of stock under employee stock purchase plans | 0 | 518 |
| Awarded restricted stock, net of forfeitures | 6,208 | 4,305 |
| Cancellation of performance-based restricted stock and forfeitures | 475 | 258 |
| Balance at end of period | (5,243) | (12,703) |

| | | |
|---|---|---|
| **Total Stockholders Equity** | $ 8,829,166 | 7,666,968 |

See notes to consolidated financial statements, page 7

*6*

Table of Contents

***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 2 through 6 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, 2010. 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, 2011, and the results of operations, cash flows and changes in stockholders equity for the three-month and six-month periods ended June 30, 2011 and 2010, in conformity with accounting principles generally accepted in the United States. In preparing the financial statements of the Company in conformity with accounting principles generally accepted in the United States, management has made a number of estimates and assumptions related to the reporting of assets, liabilities, revenues, and expenses and the disclosure of contingent assets and liabilities. Actual results may differ from the estimates.

Financial statements and notes to consolidated financial statements included in this Form 10-Q report should be read in conjunction with the Company s 2010 Form 10-K report, as certain notes and other pertinent information have been abbreviated or omitted in this report. Financial results for the three-month and six-month periods ended June 30, 2011 are not necessarily indicative of future results.

**Note B  Property, Plant and Equipment**

Under U.S. generally accepted accounting principles for companies that use the successful efforts method of accounting, exploratory well costs should continue to be capitalized when the well has found a sufficient quantity of reserves to justify its completion as a producing well and the company is making sufficient progress assessing the reserves and the economic and operating viability of the project.

At June 30, 2011, the Company had total capitalized exploratory well costs pending the determination of proved reserves of $532.9 million. The following table reflects the net changes in capitalized exploratory well costs during the six-month periods ended June 30, 2011 and 2010.

| (Thousands of dollars) | 2011 | 2010 |
|---|---|---|
| Beginning balance at January 1 | $ 497,765 | 369,862 |
| Additions pending the determination of proved reserves | 35,138 | 60,562 |
| Reclassifications to proved properties based on the determination of proved reserves | 0 | 0 |
| Balance at June 30 | $ 532,903 | 430,424 |

The following table provides an aging of capitalized exploratory well costs based on the date the drilling was completed for each individual well and the number of projects for which exploratory well costs have been capitalized. The projects are aged based on the last well drilled in the project.

| | June 30, | | | | | |
|---|---|---|---|---|---|---|
| | 2011 | | | 2010 | | |
| (Thousands of dollars) | Amount | No. of Wells | No. of Projects | Amount | No. of Wells | No. of Projects |
| Aging of capitalized well costs: | | | | | | |
| Zero to one year | $ 116,514 | 16 | 5 | $ 103,705 | 14 | 5 |
| One to two years | 96,709 | 11 | 2 | 102,446 | 10 | 4 |
| Two to three years | 104,420 | 8 | 4 | 17,946 | 2 | 2 |
| Three years or more | 215,260 | 32 | 5 | 206,327 | 32 | 4 |
| | $ 532,903 | 67 | 16 | $ 430,424 | 58 | 15 |

Of the $416.4 million of exploratory well costs capitalized more than one year at June 30, 2011, $252.9 million is in Malaysia, $136.9 million is in the U.S., $15.2 million is in Republic of the Congo, and $11.4 million is in Canada. In Malaysia either further appraisal or development drilling is planned and/or development studies/plans are in various stages of completion. In the U.S. drilling and development operations are planned. In Republic of the Congo further appraisal drilling is planned. In Canada a drilling and development program continues.

**Table of Contents**

***NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Contd.)***

**Note B Property, Plant and Equipment *(Contd.)***

In July 2010, the Company announced that its Board of Directors had approved plans to exit the U.S. refining and U.K. refining and marketing businesses. These operations are encompassed within the U.S. manufacturing and U.K. refining and marketing segments presented in Note P. On July 25, 2011, the Company announced that it had entered into an agreement to sell the Superior, Wisconsin refinery and related assets for $214 million. As part of this agreement, liquid inventories at these locations will also be sold at fair value. The Company expects to report a gain on this transaction, but the gain will vary based primarily on the level and price of liquid inventories held in storage at the time the sale is completed, which is expected to occur late in the third quarter or early in the fourth quarter. The sale process for the Meraux, Louisiana refinery and U.K. downstream assets continues. Based on current market conditions, it is possible that the Company could incur a loss on future sales of the Meraux refinery and U.K. downstream assets. The Company expects that the results of these operations will be presented as discontinued operations in future periods when the criteria for held for sale under U.S. generally accepted accounting principles have been met.

**Note C Inventories**

Inventories are carried at the lower of cost or market. The cost of crude oil and finished products is predominantly determined on the last-in, first-out (LIFO) method. At June 30, 2011 and December 31, 2010, the carrying value of inventories under the LIFO method was $974.3 million and $735.1 million, respectively, less than such inventories would have been valued using the first-in, first-out (FIFO) method.

**Note D Financing Arrangements**

In June 2011, the Company replaced its $1.9 billion committed credit facility that was scheduled to expire in July 2012 with a new five-year $1.5 billion credit facility. Borrowings under the new facility bear interest at 1.5% above LIBOR based on the Company s current credit rating as of June 30, 2011. The new committed facility did not alter the ability of the Company to borrow under other existing credit facilities, nor did it impact its shelf registration statement on file with the U.S. Securities and Exchange Commission that permits the offer and sale of debt and/or equity securities through September 2012.

Ten year notes totalling $350 million, which mature in May 2012, have been reclassified from Long-term debt to Current maturities of long-term debt as of June 30, 2011.

**Note E Cash Flow Disclosures**

Additional disclosures regarding cash flow activities are provided below.

| | Six Months Ended June 30, | |
|---|---|---|
| | 2011 | 2010 |
| Net (increase) decrease in operating working capital other than cash and cash equivalents: | | |
| (Increase) decrease in accounts receivable | $ (289,404) | 138,577 |
| (Increase) in inventories | (151,125) | (287,653) |
| (Increase) in prepaid expenses | (37,919) | (11,347) |
| (Increase) decrease in deferred income tax assets | 2,567 | (55,625) |
| Increase in accounts payable and accrued liabilities | 4,140 | 375,159 |
| Increase in current income tax liabilities | 16,086 | 90,669 |
| Total | $ (455,655) | 249,780 |

| | | |
|---|---|---|
| Supplementary disclosures: | | |
| Cash income taxes paid | $ 375,666 | 243,648 |
| Interest paid, net of amounts capitalized | 14,896 | 20,408 |

**Note F Employee and Retiree Benefit Plans**

The Company has defined benefit pension plans that are principally noncontributory and cover most full-time employees. All pension plans are funded except for the U.S. and Canadian nonqualified supplemental plans and the U.S. directors plan. All U.S. tax qualified plans meet the funding requirements of federal laws and regulations. Contributions to foreign plans are based on local laws and tax regulations. The Company also sponsors health care and life insurance benefit plans, which are not funded, that cover most retired U.S. employees. The health care benefits are contributory; the life insurance benefits are noncontributory.

**Table of Contents**

***NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Contd.)***

**Note F Employee and Retiree Benefit Plans *(Contd.)***

The table that follows provides the components of net periodic benefit expense for the three-month and six-month periods ended June 30, 2011 and 2010.

| | Three Months Ended June 30, | | | |
|---|---|---|---|---|
| | Pension Benefits | | Other Postretirement Benefits | |
| (Thousands of dollars) | 2011 | 2010 | 2011 | 2010 |
| Service cost | $ 5,952 | 5,197 | 1,290 | 920 |
| Interest cost | 7,943 | 7,433 | 1,718 | 1,474 |
| Expected return on plan assets | (6,869) | (5,891) | 0 | 0 |
| Amortization of prior service cost | 339 | 384 | (66) | (66) |
| Amortization of transitional asset | (53) | (129) | 2 | 0 |
| Recognized actuarial loss | 2,542 | 2,988 | 787 | 596 |
| Net periodic benefit expense | $ 9,854 | 9,982 | 3,731 | 2,924 |

| | Six Months Ended June 30, | | | |
|---|---|---|---|---|
| | Pension Benefits | | Other Postretirement Benefits | |
| (Thousands of dollars) | 2011 | 2010 | 2011 | 2010 |
| Service cost | $ 11,848 | 10,456 | 2,514 | 1,808 |
| Interest cost | 15,936 | 14,881 | 3,365 | 2,905 |
| Expected return on plan assets | (13,794) | (11,742) | 0 | 0 |
| Amortization of prior service cost | 683 | 771 | (130) | (130) |
| Amortization of transitional asset | (104) | (256) | 4 | 0 |
| Recognized actuarial loss | 5,118 | 5,953 | 1,540 | 1,174 |
| Net periodic benefit expense | $ 19,687 | 20,063 | 7,293 | 5,757 |

During the six-month period ended June 30, 2011, the Company made contributions of $27.1 million to its defined benefit pension and postretirement benefit plans. Remaining funding in 2011 for the Company s defined benefit pension and postretirement plans is anticipated to be $18.3 million.

In March 2010, the United States Congress enacted a health care reform law. Along with other provisions, the law (a) eliminates the tax free status of federal subsidies to companies with qualified retiree prescription drug plans that are actuarially equivalent to Medicare Part D plans beginning in 2013; (b) imposes a 40% excise tax on high-cost health plans as defined in the law beginning in 2018; (c) eliminates lifetime or annual coverage limits and required coverage for preventative health services beginning in September 2010; and (d) imposed a fee of $2 (subsequently adjusted for inflation) for each person covered by a health insurance policy beginning in September 2010. The Company provides a health care benefit plan to eligible U.S. employees and most U.S. retired employees. The new law did not significantly affect the Company s consolidated financial statements as of June 30, 2011 and 2010 and for the three-month and six-month periods then ended. The Company continues to evaluate the various components of the law as further guidance is issued and cannot predict with certainty all the ways it may impact the Company. However, based on the evaluation performed to date, the Company currently believes that the health care reform law will not have a material effect on its financial condition, net income or cash flow in future periods.

**Note G Incentive Plans**

The costs resulting from all share-based payment transactions are recognized as an expense in the financial statements using a fair value-based measurement method over the periods that the awards vest.

The 2007 Annual Incentive Plan (2007 Annual Plan) authorizes the Executive Compensation Committee (the Committee) to establish specific performance goals associated with annual cash awards that may be earned by officers, executives and other key employees. Cash awards under the 2007 Annual Plan are determined based on the Company s actual financial and operating results as measured against the performance goals established by the Committee. The 2007 Long-Term Incentive Plan (2007 Long-Term Plan) authorizes the Committee to make grants of the Company s Common Stock to employees. These grants may be in the form of stock options (nonqualified or incentive), stock appreciation rights (SAR), restricted stock, restricted stock units, performance units, performance shares, dividend equivalents and other stock-based incentives. The 2007 Long-Term Plan expires in 2017. A total of 6,700,000 shares are issuable during the life of the 2007 Long-Term Plan, with annual grants limited to 1% of

**Table of Contents**

***NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Contd.)***

**Note G Incentive Plans *(Contd.)***

Common shares outstanding. The Company has an Employee Stock Purchase Plan that permits the issuance of up to 980,000 shares through September 30, 2017. The Company also has a Stock Plan for Non-Employee Directors that permits the issuance of restricted stock and stock options or a combination thereof to the Company s Directors.

In February 2011, the Committee granted stock options for 1,397,312 shares at an exercise price of $67.635 per share. The Black-Scholes valuation for these awards was $20.34 per option. The Committee also granted 521,423 performance-based restricted stock units in February 2011 under the 2007 Long-Term Plan. The fair value of the performance-based restricted stock units, using a Monte Carlo valuation model, ranged from $38.94 to $64.89 per unit. Also in February the Committee granted 29,115 shares of time-based restricted stock to the Company s Directors under the Non-employee Director Plan. These shares vest on the third anniversary of the date of grant. The fair value of these awards was estimated based on the fair market value of the Company s stock on the date of grant, which was $67.64 per share.

Cash received from options exercised under all share-based payment arrangements for the six-month periods ended June 30, 2011 and 2010 was $7.9 million and $14.8 million, respectively. The actual income tax benefit realized for the tax deductions from option exercises of the share-based payment arrangements totaled $7.4 million and $5.9 million for the six-month periods ended June 30, 2011 and 2010, respectively.

Amounts recognized in the financial statements with respect to share-based plans are as follows.

| | Six Months Ended June 30, | |
|---|---|---|
| (Thousands of dollars) | 2011 | 2010 |
| Compensation charged against income before tax benefit | $ 22,123 | 21,048 |
| Related income tax benefit recognized in income | 6,607 | 4,744 |

**Note H Earnings per Share**

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, 2011 and 2010. 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) | 2011 | 2010 | 2011 | 2010 |
| Basic method | 193,481,601 | 191,585,996 | 193,267,154 | 191,394,728 |
| Dilutive stock options and restricted stock units | 1,434,593 | 1,583,103 | 1,375,037 | 1,426,759 |
| Diluted method | 194,916,194 | 193,169,099 | 194,642,191 | 192,821,487 |

Certain options to purchase shares of common stock were outstanding during the 2011 and 2010 periods but were not included in the computation of diluted EPS because the incremental shares from assumed conversion were antidilutive. These included 994,730 shares at a weighted average share price of $67.34 in each 2011 period and 2,263,204 shares at a weighted average share price of $58.77 in each 2010 period.

**Note I Income Taxes**

The Company s effective income tax rate generally exceeds the statutory U.S. tax rate of 35%. The effective tax rate is calculated as the amount of income tax expense divided by income before income tax expense. For the three-month and six-month periods in 2011 and 2010, the Company s effective income tax rates were as follows:

| | 2011 | 2010 |
|---|---|---|
| Three months ended June 30 | 43.6% | 38.8% |
| Six months ended June 30 | 42.7% | 42.4% |

*NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Contd.)*

**Note I Income Taxes** ***(Contd.)***

The effective tax rates for the periods presented exceeded the U.S. statutory tax rate of 35% due to several factors, including: the effects of income generated in foreign tax jurisdictions; U.S. state tax expense; and certain expenses, including exploration and other expenses in certain foreign jurisdictions, for which no income tax benefits are available or are not presently being recorded due to a lack of reasonable certainty of adequate future revenue against which to utilize these expenses as deductions. The tax rates for the three-month and six-month periods in 2010 benefited 1.3% and 0.8%, respectively, for an income tax adjustment in the U.K.

The Company s tax returns in multiple jurisdictions are subject to audit by taxing authorities. These audits often take years to complete and settle. Although the Company believes that recorded liabilities for unsettled issues are adequate, additional gains or losses could occur in future years from resolution of outstanding unsettled matters. As of June 30, 2011, the earliest years remaining open for audit and/or settlement in our major taxing jurisdictions are as follows: United States 2007; Canada 2006; United Kingdom 2009; and Malaysia 2006.

In July 2011, the United Kingdom enacted a supplemental tax for oil and gas companies effective retroactive to March 2011. The supplemental tax increased the total tax rate from 50% to 62% for oil and gas companies. The Company will record the effect of this tax increase in its consolidated financial statements in the third quarter 2011. The supplemental tax is estimated to increase tax expense by approximately $19 million for the full year 2011, with approximately $15 million of this increase recorded in the third quarter 2011. The majority of the third quarter impact is an adjustment to increase the carrying value of net deferred tax liabilities associated with U.K. upstream operations.

**Note J Financial Instruments and Risk Management**

Murphy periodically utilizes derivative instruments to manage certain risks related to 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. The Company has a risk management control system to monitor commodity price risks and any derivatives obtained to manage a portion of such risks. For accounting purposes, the Company has not designated any derivative contracts as hedges, and therefore, it recognizes all gains and losses on derivative contracts in its Consolidated Statements of Income.

*Commodity Purchase Price Risks* The Company is subject to commodity price risks related to crude oil feedstocks it holds in inventory at its refineries. Short-term derivative instruments were outstanding at June 30, 2011 and 2010 to manage the cost of about 0.2 million barrels and 1.1 million barrels, respectively, of crude oil and other feedstocks at the Company s U.S. refineries. The total impact of marking to market these contracts reduced income before taxes by $0.2 million in the six-month period ended June 30, 2011 and increased income before taxes by $2.3 million in the six-month period ended June 30, 2010. Additionally, there was an accounts payable of $9.1 million related to matured but unsettled crude oil derivative contracts at June 30, 2011.

The Company is also subject to commodity price risk related to corn that it will purchase in the future for feedstock or that it holds in inventory at its ethanol production facilities in the United States. At June 30, 2011 and 2010, the Company had open physical delivery fixed-price purchase commitment contracts for approximately 10.8 million and 2.9 million bushels of corn, respectively, for processing at its ethanol plants. The Company also had outstanding derivative contracts to sell a similar volume of these fixed-priced quantities and buy them back at future prices in effect on the expected date of delivery under the purchase commitment contracts. Additionally, at June 30, 2011, the Company had outstanding derivative contracts to sell 2.6 million bushels of corn and buy them back when certain corn inventories are expected to be processed at the Hereford, Texas facility. The impact of marking to market these corn commodity derivative contracts increased income before taxes by $1.9 million in the six-month period ended June 30, 2011 and decreased income before taxes by $0.4 million in the six-month period ended June 30, 2010.

*Foreign Currency Exchange Risks* The Company is subject to foreign currency exchange risk associated with operations in countries outside the U.S. Short-term derivative instruments were outstanding at June 30, 2011 and 2010 to manage the risk of certain income tax payments due in 2010 and later years that are payable in Malaysian ringgits. The equivalent U.S. dollars of Malaysian ringgit derivative contracts open at June 30, 2011 and 2010 were approximately $279.0 million and $281.0 million, respectively. Short-term derivative instrument contracts totaling $17.0 million and $54.0 million U.S. dollars were also outstanding at June 30, 2011 and 2010, respectively, to manage the risk of certain U.S. dollar accounts receivable associated with sale of crude oil production in Canada. The impact from marking to market these foreign currency derivative contracts increased income before taxes by $12.0 million and $15.7 million for the six-month periods ended June 30, 2011 and 2010, respectively.

**Table of Contents**

***NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Contd.)***

**Note J Financial Instruments and Risk Management *(Contd.)***

At June 30, 2011 and December 31, 2010, the fair value of derivative instruments not designated as hedging instruments are presented in the following table.

| (Thousands of dollars) | June 30, 2011 Asset (Liability) Derivatives | | December 31, 2010 Asset (Liability) Derivatives | |
|---|---|---|---|---|
| Type of Derivative Contract | Balance Sheet Location | Fair Value | Balance Sheet Location | Fair Value |
| Commodity | Accounts receivable | $ 10,791 | Accounts receivable | $ 750 |
| Commodity | | | Accounts payable | (626) |
| Foreign exchange | Accounts receivable | 11,147 | Accounts receivable | 7,261 |

For the three-month and six-month periods ended June 30, 2011 and 2010, the gains and losses recognized in the Consolidated Statements of Income for derivative instruments not designated as hedging instruments are presented in the following table.

| (Thousands of dollars) | Statement of Income | Gain (Loss) Three Months Ended June 30, | | Six Months Ended June 30, | |
|---|---|---|---|---|---|
| Type of Derivative Contract | Location | 2011 | 2010 | 2011 | 2010 |
| Commodity | Crude oil and product purchases | $ 12,952 | 2,772 | (1,481) | 610 |
| Foreign exchange | Interest and other income | 2,463 | 1,397 | 11,990 | 15,727 |
| | | $ 15,415 | 4,169 | 10,509 | 16,337 |

The Company carries certain assets and liabilities at fair value in its Consolidated Balance Sheets. The fair value hierarchy is based on the quality of inputs used to measure fair value, with Level 1 being the highest quality and Level 3 being the lowest quality. Level 1 inputs are quoted prices in active markets for identical assets or liabilities. Level 2 inputs are observable inputs other than quoted prices included within Level 1. Level 3 inputs are unobservable inputs which reflect assumptions about pricing by market participants.

The carrying value of assets and liabilities recorded at fair value on a recurring basis at June 30, 2011 and December 31, 2010 are presented in the following table.

| | June 30, 2011 | | | | December 31, 2010 | | | |
|---|---|---|---|---|---|---|---|---|
| (Thousands of dollars) | Level 1 | Level 2 | Level 3 | Total | Level 1 | Level 2 | Level 3 | Total |
| Assets | | | | | | | | |
| Foreign exchange derivative contracts | $ 0 | 11,147 | 0 | 11,147 | 0 | 7,261 | 0 | 7,261 |
| Commodity derivative contracts | 0 | 10,791 | 0 | 10,791 | 0 | 750 | 0 | 750 |
| | $ 0 | 21,938 | 0 | 21,938 | 0 | 8,011 | 0 | 8,011 |
| Liabilities | | | | | | | | |
| Nonqualified employee savings plans | $ (7,948) | 0 | 0 | (7,948) | (7,672) | 0 | 0 | (7,672) |

| | | | | | | | | |
|---|---|---|---|---|---|---|---|---|
| Commodity derivative contracts | 0 | 0 | 0 | 0 | 0 | (626) | 0 | (626) |
| | $ (7,948) | 0 | 0 | (7,948) | (7,672) | (626) | 0 | (8,298) |

The fair value of commodity derivative contracts was determined based on market quotes for West Texas Intermediate crude oil and for No. 2 yellow corn. The fair value of foreign exchange derivative contracts was based on market quotes for similar contracts at the balance sheet date. The income effect of changes in fair value of commodity derivative contracts is recorded in Crude Oil and Product Purchases in the Consolidated Statements of Income and changes in fair value of foreign exchange derivative contracts is recorded in Interest and Other Income. The nonqualified employee savings plan is an unfunded savings plan through which the participants seek a return via phantom investments in equity securities and/or mutual funds. The fair value of this liability was based on quoted prices for these equity securities and mutual funds. The income effect of changes in the fair value of nonqualified employee savings plan is recorded in Selling and General Expenses.

Table of Contents

*NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Contd.)*

**Note K Accumulated Other Comprehensive Income**

The components of Accumulated Other Comprehensive Income on the Consolidated Balance Sheets at June 30, 2011 and December 31, 2010 are presented in the following table.

| (Thousands of dollars) | June 30, 2011 | Dec. 31, 2010 |
|---|---|---|
| Foreign currency translation gains, net of tax | $ 710,433 | 587,408 |
| Retirement and postretirement benefit plan losses, net of tax | (133,607) | (137,980) |
| Accumulated other comprehensive income | $ 576,826 | 449,428 |

**Note L Environmental and 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; royalty and revenue sharing increases; 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, and may be taken 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.

Murphy and other companies in the oil and gas industry are subject to numerous federal, state, local and foreign laws and regulations dealing with the environment. Violation of federal or state environmental laws, regulations and permits can result in the imposition of significant civil and criminal penalties, injunctions and construction bans or delays. A discharge of hazardous substances into the environment could, to the extent such event is not insured, subject the Company to substantial expense, including both the cost to comply with applicable regulations and claims by neighboring landowners and other third parties for any personal injury and property damage that might result.

The Company currently owns or leases, and has in the past owned or leased, properties at which hazardous substances have been or are being handled. Although the Company has used operating and disposal practices that were standard in the industry at the time, hazardous substances may have been disposed of or released on or under the properties owned or leased by the Company or on or under other locations where these wastes have been taken for disposal. In addition, many of these properties have been operated by third parties whose treatment and disposal or release of hydrocarbons or other wastes were not under Murphy s control. Under existing laws the Company could be required to remove or remediate previously disposed wastes (including wastes disposed of or released by prior owners or operators), to clean up contaminated property (including contaminated groundwater) or to perform remedial plugging operations to prevent future contamination. While some of these historical properties are in various stages of negotiation, investigation, and/or cleanup, the Company is investigating the extent of any such liability and the availability of applicable defenses and believes costs related to these sites will not have a material adverse affect on Murphy s net income, financial condition or liquidity in a future period.

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. Although regulatory authorities may require more costly alternatives than the proposed processes, the cost of such potential alternative processes is not expected to exceed the accrued liability by a material amount. Certain environmental expenditures are likely to be recovered by the Company from other sources, primarily environmental funds maintained by certain states. Since no assurance can be given that future recoveries from other sources will occur, the Company has not recorded a benefit for likely recoveries.

Table of Contents

*NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Contd.)*

**Note L Environmental and Other Contingencies *(Contd.)***

The U.S. Environmental Protection Agency (EPA) currently considers the Company to be a Potentially Responsible Party (PRP) at one Superfund site. The potential total cost to all parties to perform necessary remedial work at the Superfund site may be substantial. However, based on current negotiations and available information, the Company believes that it is a de minimis party as to ultimate responsibility at this Superfund site. The Company has not recorded a liability for remedial costs on the Superfund site. 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 site or other Superfund sites. The Company believes that its share of the ultimate costs to clean-up the Superfund site will be immaterial and will not have a material adverse effect on its net income, financial condition or liquidity 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 the Company s future net income, cash flows or liquidity.

Litigation arising out of a June 10, 2003 fire in the Residual Oil Supercritical Extraction (ROSE) unit at the Company s Meraux, Louisiana refinery was settled in July 2009 and memorialized via a filing in the U.S. District Court for the Eastern District of Louisiana on July 24, 2009. An arbitral tribunal heard the Company s claim for indemnity from one of its insurers, AEGIS, in September 2009 and the tribunal ruled in favor of the Company. The Company continues to believe that the ultimate resolution of the June 2003 ROSE fire matter will not have a material adverse effect on its net income, financial condition or liquidity in a future period.

Murphy is engaged in a number of other legal proceedings, all of which Murphy considers routine and incidental to its business. Based on information currently available to the Company, the ultimate resolution of these matters is not expected to have a material adverse effect on the Company s net income, financial condition or liquidity 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, 2011, the Company had contingent liabilities of $7.8 million under a financial guarantee and $332.2 million on outstanding letters of credit. The Company has not accrued a liability in its Consolidated Balance Sheets related to these letters of credit because it is believed that the likelihood of having these drawn is remote.

**Note M Commitments**

The Company has entered into forward sales contracts to mitigate the price risk for a portion of its 2011 and 2012 natural gas sales volumes in the Tupper and Tupper West areas in Western Canada. The contracts call for natural gas deliveries of approximately 99 million cubic feet per day in the last six months of 2011 at an average price of Cdn$4.90 per MCF, with the contracts calling for delivery at the AECO C sales point. In 2012, contracts call for delivery at AECO C of approximately 50 million cubic feet per day at an average price of Cdn$4.43 per MCF. These contracts have been accounted for as a normal sale for accounting purposes.

**Note N Terra Nova Working Interest Redetermination**

The joint agreement between the owners of the Terra Nova field, offshore Eastern Canada, requires a redetermination of working interests based on an analysis of reservoir quality among fault separated areas where varying ownership interests exist. The Terra Nova redetermination process was essentially completed in 2010, and the Company s working interest at Terra Nova was reduced from its original 12.0% to approximately 10.475%. The Company made a cash settlement payment in the first quarter 2011 to certain Terra Nova partners for the value of oil sold since February 2005 related to the working interest reduction. The Company had recorded cumulative expense of $102.1 million through 2010 based on the working interest reduction. Based on the final settlement paid in 2011, the Company recorded a benefit of $5.4 million in the six-month period ended June 30, 2011 due to the ultimate cost of the redetermination settlement being less than originally estimated. The 2010 expense and 2011 benefit have been reflected as Redetermination of Terra Nova Working Interest in the Consolidated Statements of Income.

*14*

*NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Contd.)*

**Note O    Accounting Matters**

The Company adopted new guidance issued by the Financial Accounting Standards Board (FASB) regarding accounting for transfers of financial assets effective January 1, 2010. This guidance makes the concept of a qualifying special-purpose entity as defined previously no longer relevant for accounting purposes. Therefore, formerly qualifying special-purpose entities must be reevaluated for consolidation by reporting entities in accordance with the applicable consolidation guidance. This adoption of this guidance did not have a significant effect on the Company s consolidated financial statements.

The Company adopted, effective January 1, 2010, new guidance issued by the FASB that requires a company to perform an analysis to determine whether its variable interests give it a controlling financial interest in a variable interest entity. The primary beneficiary of a variable interest entity has both the power to direct the activities of the entity that most significantly impact the entity s economic performance and the obligation to absorb potentially significant losses of the entity or the right to receive potentially significant benefits from the entity. A company is required to make ongoing reassessments of whether it is the primary beneficiary of a variable interest entity. This guidance also amended previous guidance for determining whether an entity is considered a variable interest entity. The adoption of this guidance did not have a significant effect on the Company s consolidated financial statements.

In July 2010, the FASB issued new accounting guidance that expanded the disclosure requirements about financing receivables and the related allowance for credit losses. This guidance became effective for the Company at December 31, 2010. Because the Company has no significant financing receivables that extend beyond one year, the impact of this guidance did not have a significant effect on its consolidated financial statement disclosures.

The United States Congress passed the Dodd-Frank Act in 2010. Among other requirements, the law requires companies in the oil and gas industry to disclose payments made to the U.S. Federal and all foreign governments. The SEC was directed to develop the reporting requirements in accordance with the law. The SEC has issued preliminary guidance and has sought feedback thereon from all interested parties. The preliminary rules indicated that payment disclosures would be required at a project level within the annual Form 10-K report beginning with the year ending December 31, 2012. The Company cannot predict the final disclosure requirements that will be required by the Dodd-Frank Act.

**Table of Contents**

***NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Contd.)***

**Note P Business Segments**

| (Millions of dollars) | Total Assets at June 30, 2011 | Three Mos. Ended June 30, 2011 External Revenues | Three Mos. Ended June 30, 2011 Inter-segment Revenues | Three Mos. Ended June 30, 2011 Income (Loss) | Three Mos. Ended June 30, 2010 External Revenues | Three Mos. Ended June 30, 2010 Inter-segment Revenues | Three Mos. Ended June 30, 2010 Income (Loss) |
|---|---|---|---|---|---|---|---|
| Exploration and production* | | | | | | | |
| United States | $ 1,721.5 | 198.3 | 0 | 52.1 | 167.6 | 0 | 14.5 |
| Canada | 3,614.7 | 274.2 | 54.5 | 95.8 | 232.2 | 8.7 | 62.3 |
| Malaysia | 3,361.8 | 439.8 | 0 | 166.0 | 429.4 | 0 | 158.2 |
| United Kingdom | 197.1 | 33.5 | 0 | 9.3 | 29.1 | 0 | 8.4 |
| Republic of the Congo | 725.9 | 33.1 | 0 | (3.3) | 25.4 | 0 | (8.9) |
| Other | 84.5 | 23.1 | 0 | (76.6) | .3 | 0 | (15.4) |
| Total | 9,705.5 | 1,002.0 | 54.5 | 243.3 | 884.0 | 8.7 | 219.1 |
| Refining and marketing | | | | | | | |
| United States manufacturing | 1,587.4 | 334.3 | 1,735.1 | 27.3 | 210.9 | 1,047.2 | 9.8 |
| United States marketing | 1,714.5 | 5,735.1 | 0 | 80.2 | 4,080.9 | 0 | 69.6 |
| United Kingdom | 1,114.8 | 1,641.8 | 0 | (15.8) | 416.6 | 0 | 4.4 |
| Total | 4,416.7 | 7,711.2 | 1,735.1 | 91.7 | 4,708.4 | 1,047.2 | 83.8 |
| Total operating segments | 14,122.2 | 8,713.2 | 1,789.6 | 335.0 | 5,592.4 | 1,055.9 | 302.9 |
| Corporate | 1,444.8 | 8.3 | 0 | (23.4) | (.5) | 0 | (30.6) |
| Total | $ 15,567.0 | 8,721.5 | 1,789.6 | 311.6 | 5,591.9 | 1,055.9 | 272.3 |

| (Millions of dollars) | Six Months Ended June 30, 2011 External Revenues | Six Months Ended June 30, 2011 Inter-segment Revenues | Six Months Ended June 30, 2011 Income (Loss) | Six Months Ended June 30, 2010 External Revenues | Six Months Ended June 30, 2010 Inter-segment Revenues | Six Months Ended June 30, 2010 Income (Loss) |
|---|---|---|---|---|---|---|
| Exploration and production* | | | | | | |
| United States | $ 366.5 | 0 | 68.6 | 342.6 | 0 | 33.2 |
| Canada | 520.3 | 94.7 | 182.2 | 423.5 | 40.3 | 111.5 |
| Malaysia | 957.3 | 0 | 361.8 | 933.3 | 0 | 331.7 |
| United Kingdom | 63.7 | 0 | 18.3 | 81.5 | 0 | 25.0 |
| Republic of the Congo | 67.7 | 0 | .3 | 53.7 | 0 | (6.4) |
| Other | 24.4 | 0 | (127.5) | 2.6 | 0 | (28.9) |
| Total | 1,999.9 | 94.7 | 503.7 | 1,837.2 | 40.3 | 466.1 |
| Refining and marketing | | | | | | |
| United States manufacturing | 578.5 | 3,165.8 | 56.0 | 339.1 | 1,675.4 | (13.8) |
| United States marketing | 10,534.0 | 0 | 90.9 | 7,686.5 | 0 | 78.5 |
| United Kingdom | 2,946.9 | 0 | (24.5) | 959.0 | 0 | (10.6) |
| Total | 14,059.4 | 3,165.8 | 122.4 | 8,984.6 | 1,675.4 | 54.1 |

| | | | | | | |
|---|---|---|---|---|---|---|
| Total operating segments | 16,059.3 | 3,260.5 | 626.1 | 10,821.8 | 1,715.7 | 520.2 |
| Corporate | 13.9 | 0 | (45.6) | (49.7) | 0 | (99.0) |
| Total | $ 16,073.2 | 3,260.5 | 580.5 | 10,772.1 | 1,715.7 | 421.2 |

* Additional details about results of oil and gas operations are presented in the tables on pages 23 and 24.

**Table of Contents**

***NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Contd.)***

**Note P Business Segments *(Contd.)***

United States Manufacturing operations include two refineries and two ethanol production facilities. The Company acquired an unfinished ethanol production facility in Hereford, Texas, in the third quarter 2010; construction of the plant was completed and the plant started operations at the end of March 2011. United States Marketing includes retail and wholesale fuel marketing operations. Transactions between these two U.S. downstream segments are recorded at agreed transfer prices, which approximate market value, and eliminations have been made as necessary within the consolidated financial statements. The Company previously announced its intention to sell its two U.S. refineries and its U.K. downstream operations during 2011. See Note B for further discussion of this matter.

Table of Contents

***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 2011 was $311.6 million ($1.60 per diluted share) compared to net income of $272.3 million ($1.41 per diluted share) in the second quarter of 2010. The income improvement in 2011 primarily related to higher sales prices for the Company s crude oil production and higher margins on U.S. refining and marketing operations. The 2011 quarter also included an after-tax gain of $13.1 million related to sale of the Company s gas storage assets in Spain. These favorable factors were partially offset by unfavorable impacts from lower crude oil sales volumes, higher exploration expenses and significantly weaker results in U.K. downstream operations.

For the first six months of 2011, net income totaled $580.5 million ($2.98 per diluted share) compared to net income of $421.2 million ($2.18 per diluted share) for the same period in 2010. The increase in net income in 2011 compared to 2010 was also primarily attributable to higher crude oil sales prices and improved U.S. refining and marketing results. Operating results were unfavorably affected in 2011 by lower crude oil sales volumes, higher exploration expenses and a larger operating loss in U.K. downstream operations.

Murphy s net income by operating business is presented below.

| | Income (Loss) | | | |
|---|---|---|---|---|
| | Three Months Ended June 30, | | Six Months Ended June 30, | |
| (Millions of dollars) | 2011 | 2010 | 2011 | 2010 |
| Exploration and production | $ 243.3 | 219.1 | 503.7 | 466.1 |
| Refining and marketing | 91.7 | 83.8 | 122.4 | 54.1 |
| Corporate | (23.4) | (30.6) | (45.6) | (99.0) |
| Net income | $ 311.6 | 272.3 | 580.5 | 421.2 |

In the 2011 second quarter, the Company s exploration and production operations earned $243.3 million compared to $219.1 million in the 2010 quarter. Income in the 2011 quarter was favorably impacted compared to 2010 by higher crude oil sales prices, higher natural gas sales volumes, and a $13.1 million after-tax gain on sale of natural gas storage assets in Spain. Exploration expenses were $122.5 million in the second quarter of 2011 compared to $53.2 million in the same period of 2010. The Company s refining and marketing operations generated income of $91.7 million in the 2011 second quarter compared to income of $83.8 million in the same quarter of 2010. U.S. refining and marketing margins improved in the 2011 quarter, compared to the 2010 quarter, but results in the U.K. were unfavorable to the prior year. The corporate function had after-tax costs of $23.4 million in the 2011 second quarter compared to after-tax costs of $30.6 million in the 2010 period with the favorable variance in 2011 mostly due to gains on transactions denominated in foreign currencies in 2011 compared to losses on such transactions in the 2010 quarter.

In the first six months of 2011, the Company s exploration and production operations earned $503.7 million compared to $466.1 million in the same period of 2010. Earnings in 2011 compared favorably to the 2010 period primarily due to higher realized crude oil sales prices and higher natural gas sales volumes. Exploration expenses increased from $119.5 million in the first six months of 2010 to $218.8 million in the 2011 period, with the higher costs in 2011 primarily from unsuccessful wildcat drilling offshore Indonesia and Suriname. The Company s refining and marketing operations had earnings of $122.4 million in the first six months of 2011 compared to earnings of $54.1 million in the same 2010 period. The 2011 period included stronger results in the U.S. refining and marketing business compared to a year ago based on better operating margins. However, losses from U.K. downstream operations were significantly higher in 2011 compared to 2010 due to more sales volumes at very weak operating margins. Corporate after-tax costs were $45.6 million in the 2011 period compared to after-tax costs of $99.0 million in the 2010 period. The current period had a favorable impact from gains on transactions denominated in foreign currencies, while the prior year included significant losses from these transactions.

Table of Contents

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

**Results of Operations (Contd.)**

*Exploration and Production*

Results of 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) | 2011 | 2010 | 2011 | 2010 |
| Exploration and production | | | | |
| United States | $ 52.1 | 14.5 | 68.6 | 33.2 |
| Canada | 95.8 | 62.3 | 182.2 | 111.5 |
| Malaysia | 166.0 | 158.2 | 361.8 | 331.7 |
| United Kingdom | 9.3 | 8.4 | 18.3 | 25.0 |
| Republic of the Congo | (3.3) | (8.9) | 0.3 | (6.4) |
| Other International | (76.6) | (15.4) | (127.5) | (28.9) |
| Total | $ 243.3 | 219.1 | 503.7 | 466.1 |

*Second quarter 2011 vs. 2010*

United States exploration and production operations reported earnings of $52.1 million in the second quarter of 2011 compared to earnings of $14.5 million in the 2010 quarter. Earnings improved in the 2011 period primarily due to higher realized oil sales prices. Oil and natural gas production volumes were lower in 2011 due to decline at Thunder Hawk and other fields in the Gulf of Mexico. A significant portion of this production decline was attributable to an inability to obtain drilling permits in the Gulf of Mexico following the Macondo incident in April 2010. Production expenses increased $2.7 million in 2011 compared to 2010 mostly due to higher production in the Eagle Ford Shale area of South Texas. Depreciation expense was $37.3 million less in 2011 due to lower oil and natural gas production volumes and lower per-barrel capital amortization rates in the Gulf of Mexico in the current quarter. Selling and general expenses in the 2011 period increased $5.6 million from the prior year primarily due to higher costs for employee compensation and other professional services.

Operations in Canada had earnings of $95.8 million in the second quarter 2011 compared to earnings of $62.3 million in the 2010 quarter. Canadian earnings increased in the 2011 quarter mostly due to higher crude oil and natural gas sales prices, and higher natural gas sales volumes. Natural gas volumes increased in 2011 due to start-up of Tupper West area production in February 2011 and higher volumes produced at the nearby Tupper Main area. Oil production decreased in the 2011 period compared to 2010 primarily due to curtailment associated with equipment constraints on the Terra Nova field production facility, and lower volumes at Syncrude caused by downtime for severe forest fires in Northern Alberta. Production and depreciation expenses for conventional oil operations in Canada were unfavorable in 2011 by $10.9 million and $24.4 million, respectively, due primarily to higher gas volumes produced at Tupper West and Tupper Main. Production expenses at Syncrude increased $10.6 million in 2011 due to higher fuel and maintenance costs. The 2010 quarter included expense of $5.4 million related to a required working redetermination at the Terra Nova field, offshore Newfoundland.

Operations in Malaysia reported earnings of $166.0 million in the 2011 quarter compared to earnings of $158.2 million during the same period in 2010. Earnings rose in 2011 in Malaysia from a combination of higher crude oil sales prices and higher natural gas sales prices and sales volumes from fields offshore Sarawak. The 2011 quarter was unfavorably affected by lower crude oil sales volumes, primarily at the Kikeh field where certain wells were shut-in or curtailed awaiting rig workovers. The first well workover was successfully completed in July 2011. Production expenses were higher in the 2011 period by $14.4 million primarily due to additional maintenance costs at the Kikeh field. Depreciation expense was $15.0 million less in the 2011 quarter due to lower crude oil sales volumes. Exploration expense was $3.0 million lower in 2011 due essentially to no dry hole costs in the current quarter, but offset in part by the cost of 3-D seismic acquired in Block H, offshore Sabah.

*19*

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

**Results of Operations (Contd.)**

*Exploration and Production (Contd.)*

*Second Quarter 2011 vs. 2010 (Contd.)*

United Kingdom operations earned $9.3 million in the 2011 quarter compared to $8.4 million in the 2010 quarter. The improvement was primarily due to higher crude oil and natural gas sales prices in the 2011 quarter compared to 2010. The 2011 quarter was unfavorably affected by lower crude oil and natural gas sales volumes. Production expenses was $3.9 million higher in 2011 than 2010 due to higher maintenance costs in the current quarter at the Schiehallion and Mungo/Monan fields. Depreciation expense declined by $2.1 million in 2011 compared to 2010 primarily due to lower oil and gas sales volumes.

Operations in Republic of the Congo incurred a loss of $3.3 million in the second quarter of 2011 compared to a loss of $8.9 million in the 2010 quarter. Results improved in the current period primarily due to higher crude oil sales prices. Production expense declined by $3.4 million in 2011 versus 2010 due to less well maintenance costs at the Azurite field. Depreciation expense increased by $6.2 million in 2011 associated with a higher unit rate for capital amortization.

Other international operations reported a loss of $76.6 million in the second quarter of 2011 compared to a loss of $15.4 million in the 2010 period. The unfavorable variance in the current quarter was primarily related to higher unsuccessful exploratory drilling costs in Indonesia. The 2011 quarter included an after-tax gain of $13.1 million associated with the sale of gas storage assets in Spain.

On a worldwide basis, the Company s crude oil, condensate and gas liquids prices averaged $99.37 per barrel in the second quarter 2011 compared to $64.68 in the 2010 period. Total hydrocarbon production averaged 170,457 barrels of oil equivalent per day in the 2011 second quarter, down from the 189,951 barrels equivalent per day produced in the 2010 quarter. Average crude oil and liquids production was 94,242 barrels per day in the second quarter of 2011 compared to 131,983 barrels per day in the second quarter of 2010, with the reduction primarily attributable to lower gross oil production caused by wells shut-in or curtailed awaiting rig workovers at the Kikeh field. Canadian crude oil production in the heavy oil area and at Syncrude were lower in 2011 mostly due to downtime associated with severe forest fires in Northern Alberta. Canadian offshore crude oil production at Terra Nova was lower in the 2011 quarter due to curtailed production associated with equipment constraints on the production facility. North American natural gas sales prices averaged $4.26 per thousand cubic feet (MCF) in the 2011 quarter compared to $4.16 per MCF in the same quarter of 2010. Natural gas produced in 2011 at fields offshore Sarawak was sold at $6.40 per MCF, compared to a sale price of $5.10 per MCF in the 2010 quarter. Natural gas sales volumes averaged 457 million cubic feet per day in the second quarter 2011, up from 348 million cubic feet per day in the 2010 quarter. The increase in natural gas sales volumes in 2011 was due to start-up of the Tupper West area production in February 2011, higher production at nearby Tupper Main, and higher gas production from fields offshore Sarawak.

*Six months 2011 vs. 2010*

U.S. E&P operations had income of $68.6 million for the six months ended June 30, 2011 compared to income of $33.2 million in the 2010 period. The 2011 period benefited from higher crude oil sales prices, but natural gas sales prices were lower in the 2011 period compared to the prior year. Crude oil production volumes were lower in the 2011 quarter mostly due to declines at fields in the Gulf of Mexico, which were mostly caused by delays in obtaining drilling permits following the Macondo incident. Production expenses were $11.0 million more in 2011 than 2010 mostly due to higher production in the Eagle Ford shale area of South Texas. Depreciation expense was $64.2 million less in 2011 than 2010 due to the lower overall production volumes and a lower per-barrel capital amortization rate. Exploration expense in the 2011 period was $12.7 million above 2010 levels primarily due to higher costs at the Eagle Ford shale area for geophysical expense and undeveloped lease amortization. Selling and general expenses rose by $7.0 million in 2011 compared to 2010 essentially due to higher costs for employee compensation and other professional services.

Canadian operations had income of $182.2 million in the first half of 2011 compared to income of $111.5 million a year ago. Higher sales prices for crude oil and higher volumes of natural gas sold led to the improvement in 2011 earnings. Production and depreciation expenses increased $33.3 million and $35.5 million, respectively, in 2011 mostly related to higher volumes of natural gas produced at the Tupper West area following start-up in February 2011.

Table of Contents

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

**Results of Operations (Contd.)**

*Exploration and Production (Contd.)*

*Six Months 2011 vs. 2010 (Contd.)*

Malaysia operations earned $361.8 million in the first half of 2011 compared to earnings of $331.7 million in the 2010 period. Earnings were stronger in 2011 primarily due to higher crude oil sales prices. Additionally, the 2011 period benefited from higher sales volumes and sales prices for natural gas produced offshore Sarawak. Crude oil sales volumes at the Kikeh field were lower in 2011 than 2010 due to lower gross oil production caused by certain wells shut-in or curtailed awaiting rig workovers. Production expense in 2011 exceeded the 2010 cost by $33.7 million primarily due to higher Kikeh field maintenance. Depreciation expense was $25.1 million lower in the 2011 period due to less oil sales volumes at the Kikeh field. Exploration expense was $25.7 million lower in 2011 mostly due to less unsuccessful exploration drilling costs.

Income in the U.K. for the six-month period in 2011 was $18.3 million compared to $25.0 million a year ago with the earnings reduction primarily due to lower crude oil and natural gas sales volumes. The 2011 period benefited from higher crude oil and natural gas sales prices compared to 2010. Depreciation expense for 2011 was $5.8 million less than in 2010 due to the lower crude oil and natural gas sales volumes.

Operations in Republic of the Congo had income of $0.3 million for the six-month 2011 period, compared to a loss of $6.4 million in the 2010 period. The improvement in income in 2011 was primarily due to higher sales prices for oil produced at the offshore Azurite field. The 2011 period benefited from lower production expenses by $9.7 million due to less well maintenance costs in the current period. Depreciation expense increased $15.7 million due to a higher capital amortization rate and higher sales volumes at the Azurite oil field. Exploration expense was $1.5 million higher in 2011 than 2010 due to more costs for unsuccessful drilling, partially offset by lower geophysical costs, primarily due to a 3D seismic acquisition covering a portion of the offshore MPN block during the 2010 period.

Other international operations reported a loss of $127.5 million in the first six months of 2011 compared to a loss of $28.9 million in the 2010 period. The higher loss in the 2011 period primarily related to costs associated with unsuccessful offshore wildcat drilling in Indonesia and Suriname in 2011. Higher undeveloped leasehold amortization of $5.7 million in 2011 compared to 2010 was attributable to a new exploration license in the Central Dohuk area in the Kurdistan region of Iraq. The 2011 period included an after-tax gain of $13.1 million attributable to sale of the Company s gas storage assets in Spain.

For the first six months of 2011, the Company s sales price for crude oil, condensate and gas liquids averaged $93.04 per barrel, up from $64.59 per barrel in 2010. Total worldwide production averaged 176,272 barrels of oil equivalent per day during the six months ended June 30, 2011, down from 193,071 barrels of oil equivalent produced in the same period in 2010. Crude oil, condensate and gas liquids production in the first half of 2011 averaged 103,725 barrels per day compared to 135,502 barrels per day a year ago. The reduction was mostly attributable to lower gross oil production at the Kikeh field offshore Sabah Malaysia, where wells were shut-in or curtailed awaiting rig workovers. Crude oil production offshore eastern Canada was lower in 2011 due to curtailment associated with equipment constraints on the Terra Nova production facility. Crude oil production in the U.K. was lower in 2011 than 2010 due to field decline at Mungo/Monan and more downtime for equipment repairs at Schiehallion. Crude oil produced in Republic of the Congo increased in 2011 due to a new well coming onstream. Synthetic oil production at Syncrude increased in 2011 compared to 2010 due to higher gross production. The average sales price for North American natural gas in the first six months of 2011 was $4.30 per MCF, down from $4.61 per MCF realized in 2010. Natural gas production at fields offshore Sarawak was sold at an average price of $6.15 per MCF in 2011 compared to $4.87 per MCF in 2010. Natural gas sales volumes increased from 345 million cubic feet per day in 2010 to 435 million cubic feet per day in 2011, with the increase mostly due to start-up of natural gas production volumes at the Tupper West area in British Columbia, which came onstream in February 2011, coupled with higher production at nearby Tupper Main and higher volumes produced at Sarawak, Malaysia fields.

Additional details about results of oil and gas operations are presented in the tables on pages 23 and 24.

Table of Contents

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

**Results of Operations (Contd.)**

*Exploration and Production (Contd.)*

Selected operating statistics for the three-month and six-month periods ended June 30, 2011 and 2010 follow.

| | Three Months Ended June 30, | | Six Months Ended June 30, | |
|---|---|---|---|---|
| Exploration and Production | 2011 | 2010 | 2011 | 2010 |
| Net crude oil, condensate and gas liquids produced barrels per day | 94,242 | 131,983 | 103,725 | 135,502 |
| United States | 17,050 | 20,755 | 16,934 | 21,199 |
| Canada light | 79 | 31 | 57 | 41 |
| heavy | 5,726 | 5,920 | 6,762 | 6,200 |
| offshore | 9,279 | 12,210 | 9,043 | 12,404 |
| synthetic | 12,720 | 14,499 | 13,805 | 13,445 |
| Malaysia | 41,995 | 69,597 | 48,569 | 73,824 |
| United Kingdom | 2,369 | 4,103 | 2,725 | 4,095 |
| Republic of the Congo | 5,024 | 4,868 | 5,830 | 4,294 |
| Net crude oil, condensate and gas liquids sold barrels per day | 90,004 | 131,810 | 101,341 | 138,758 |
| United States | 17,050 | 20,755 | 16,934 | 21,199 |
| Canada light | 79 | 31 | 57 | 41 |
| heavy | 5,726 | 5,920 | 6,762 | 6,200 |
| offshore | 8,778 | 12,833 | 8,933 | 12,509 |
| synthetic | 12,720 | 14,499 | 13,805 | 13,445 |
| Malaysia | 39,279 | 70,351 | 48,447 | 76,434 |
| United Kingdom | 2,906 | 3,654 | 2,741 | 5,427 |
| Republic of the Congo | 3,466 | 3,767 | 3,662 | 3,503 |
| Net natural gas sold thousands of cubic feet per day | 457,288 | 347,806 | 435,283 | 345,414 |
| United States | 50,487 | 57,649 | 52,363 | 50,764 |
| Canada | 194,850 | 87,862 | 156,286 | 83,845 |
| Malaysia Sarawak | 176,265 | 126,469 | 173,425 | 142,434 |
| Kikeh | 31,631 | 69,971 | 48,140 | 62,586 |
| United Kingdom | 4,055 | 5,855 | 5,069 | 5,785 |
| Total net hydrocarbons produced equivalent barrels per day (1) | 170,457 | 189,951 | 176,272 | 193,071 |
| Total net hydrocarbons sold equivalent barrels per day (1) | 166,219 | 189,778 | 173,888 | 196,327 |
| Weighted average sales prices | | | | |
| Crude oil, condensate and gas liquids dollars per barrel (2) | | | | |
| United States | $ 109.21 | 74.81 | 102.47 | 75.20 |
| Canada (3) light | 99.94 | 74.87 | 97.56 | 76.83 |
| heavy | 64.55 | 47.83 | 58.03 | 51.01 |
| offshore | 115.50 | 75.14 | 108.70 | 74.98 |
| synthetic | 114.98 | 75.84 | 104.03 | 76.59 |
| Malaysia (4) | 90.05 | 57.71 | 86.88 | 57.78 |
| United Kingdom | 112.37 | 77.43 | 111.46 | 76.32 |
| Republic of the Congo | 105.16 | 74.27 | 102.19 | 71.48 |

| | | | | |
|---|---|---|---|---|
| Natural gas dollars per thousand cubic feet | | | | |
| United States (2) | $ 4.43 | 4.23 | 4.31 | 4.88 |
| Canada (3) | 4.22 | 4.11 | 4.29 | 4.44 |
| Malaysia Sarawak | 6.40 | 5.10 | 6.15 | 4.87 |
| Kikeh | 0.24 | 0.23 | 0.24 | 0.23 |
| United Kingdom (3) | 10.10 | 5.97 | 9.98 | 5.88 |

(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) Prices are net of payments under the terms of the production sharing contracts for Blocks SK 309 and K.

*22*

**Table of Contents**

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

**Results of Operations (Contd.)**

***OIL AND GAS OPERATING RESULTS THREE MONTHS ENDED JUNE 30, 2011 AND 2010***

| (Millions of dollars) | United States | Canada Conventional | Canada Synthetic | Malaysia | United Kingdom | Republic of the Congo | Other | Total |
|---|---|---|---|---|---|---|---|---|
| **Three Months Ended June 30, 2011** | | | | | | | | |
| Oil and gas sales and other operating revenues | $ 198.3 | 195.7 | 133.0 | 439.8 | 33.5 | 33.1 | 23.1 | 1,056.5 |
| Production expenses | 36.4 | 37.4 | 58.3 | 84.7 | 8.9 | 11.2 | | 236.9 |
| Depreciation, depletion and amortization | 42.8 | 71.4 | 12.8 | 75.9 | 3.7 | 18.9 | .4 | 225.9 |
| Accretion of asset retirement obligations | 2.5 | 1.2 | 2.0 | 2.7 | .8 | .1 | .1 | 9.4 |
| Exploration expenses | | | | | | | | |
| Dry holes | (.3) | | | (.1) | | .8 | 69.1 | 69.5 |
| Geological and geophysical | 2.4 | 1.0 | | 5.8 | .2 | .8 | 2.1 | 12.3 |
| Other | 4.0 | .3 | | | .1 | | 5.2 | 9.6 |
| | 6.1 | 1.3 | | 5.7 | .3 | 1.6 | 76.4 | 91.4 |
| Undeveloped lease amortization | 19.9 | 7.1 | | | | | 4.1 | 31.1 |
| Total exploration expenses | 26.0 | 8.4 | | 5.7 | .3 | 1.6 | 80.5 | 122.5 |
| Selling and general expenses | 11.0 | 3.3 | .2 | (1.3) | .9 | .7 | 10.3 | 25.1 |
| Results of operations before taxes | 79.6 | 74.0 | 59.7 | 272.1 | 18.9 | .6 | (68.2) | 436.7 |
| Income tax provisions | 27.5 | 21.9 | 16.0 | 106.1 | 9.6 | 3.9 | 8.4 | 193.4 |
| Results of operations (excluding corporate overhead and interest) | $ 52.1 | 52.1 | 43.7 | 166.0 | 9.3 | (3.3) | (76.6) | 243.3 |
| **Three Months Ended June 30, 2010** | | | | | | | | |
| Oil and gas sales and other operating revenues | $ 167.6 | 140.9 | 100.0 | 429.4 | 29.1 | 25.4 | .3 | 892.7 |
| Production expenses | 33.7 | 26.5 | 47.7 | 70.3 | 5.0 | 14.6 | | 197.8 |
| Depreciation, depletion and amortization | 80.1 | 47.0 | 12.2 | 90.9 | 5.8 | 12.7 | .3 | 249.0 |
| Accretion of asset retirement obligations | 1.7 | 1.2 | 1.6 | 2.4 | .6 | .0 | .1 | 7.6 |
| Exploration expenses | | | | | | | | |
| Dry holes | | | | 7.9 | | .1 | (.5) | 7.5 |
| Geological and geophysical | 4.7 | (.1) | | .8 | .1 | 3.1 | 1.3 | 9.9 |
| Other | 3.1 | .1 | | | .1 | (.3) | 5.2 | 8.2 |
| | 7.8 | | | 8.7 | .2 | 2.9 | 6.0 | 25.6 |
| Undeveloped lease amortization | 18.3 | 8.0 | | | | | 1.3 | 27.6 |
| Total exploration expenses | 26.1 | 8.0 | | 8.7 | .2 | 2.9 | 7.3 | 53.2 |

| | | | | | | | | |
|---|---|---|---|---|---|---|---|---|
| Terra Nova working interest redetermination | | 5.4 | | | | | | 5.4 |
| Selling and general expenses | 5.4 | 2.9 | .2 | .2 | .7 | .3 | 8.0 | 17.7 |
| Results of operations before taxes | 20.6 | 49.9 | 38.3 | 256.9 | 16.8 | (5.1) | (15.4) | 362.0 |
| Income tax provisions | 6.1 | 15.0 | 10.9 | 98.7 | 8.4 | 3.8 | | 142.9 |
| Results of operations (excluding corporate overhead and interest) | $ 14.5 | 34.9 | 27.4 | 158.2 | 8.4 | (8.9) | (15.4) | 219.1 |

Table of Contents

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

**Results of Operations (Contd.)**

*OIL AND GAS OPERATING RESULTS SIX MONTHS ENDED JUNE 30, 2011 AND 2010*

| (Millions of dollars) | United States | Canada Conventional | Canada Synthetic | Malaysia | United Kingdom | Republic of the Congo | Other | Total |
|---|---|---|---|---|---|---|---|---|
| **Six Months Ended June 30, 2011** | | | | | | | | |
| Oil and gas sales and other operating revenues | $ 366.5 | 355.2 | 259.8 | 957.3 | 63.7 | 67.7 | 24.4 | 2,094.6 |
| Production expenses | 77.5 | 68.3 | 116.8 | 187.8 | 14.5 | 16.8 | | 481.7 |
| Depreciation, depletion and amortization | 91.3 | 124.2 | 26.6 | 171.7 | 8.3 | 37.8 | .8 | 460.7 |
| Accretion of asset retirement obligations | 4.9 | 2.5 | 3.9 | 5.3 | 1.6 | .3 | .2 | 18.7 |
| Exploration expenses | | | | | | | | |
| Dry holes | .6 | | | | | 2.9 | 101.8 | 105.3 |
| Geological and geophysical | 20.6 | 2.5 | | 5.8 | .3 | 1.6 | 2.5 | 33.3 |
| Other | 7.3 | .6 | | | .2 | .1 | 11.5 | 19.7 |
| | 28.5 | 3.1 | | 5.8 | .5 | 4.6 | 115.8 | 158.3 |
| Undeveloped lease amortization | 38.3 | 14.0 | | | | | 8.2 | 60.5 |
| Total exploration expenses | 66.8 | 17.1 | | 5.8 | .5 | 4.6 | 124.0 | 218.8 |
| Terra Nova working interest redetermination | | (5.4) | | | | | | (5.4) |
| Selling and general expenses | 20.4 | 6.6 | .4 | | 1.7 | .3 | 18.1 | 47.5 |
| Results of operations before taxes | 105.6 | 141.9 | 112.1 | 586.7 | 37.1 | 7.9 | (118.7) | 872.6 |
| Income tax provisions | 37.0 | 41.7 | 30.1 | 224.9 | 18.8 | 7.6 | 8.8 | 368.9 |
| Results of operations (excluding corporate overhead and interest) | $ 68.6 | 100.2 | 82.0 | 361.8 | 18.3 | .3 | (127.5) | 503.7 |
| **Six Months Ended June 30, 2010** | | | | | | | | |
| Oil and gas sales and other operating revenues | $ 342.6 | 276.1 | 187.7 | 933.3 | 81.5 | 53.7 | 2.6 | 1,877.5 |
| Production expenses | 66.5 | 52.3 | 99.5 | 154.1 | 14.2 | 26.5 | | 413.1 |
| Depreciation, depletion and amortization | 155.5 | 93.1 | 22.2 | 196.8 | 14.1 | 22.1 | .6 | 504.4 |
| Accretion of asset retirement obligations | 3.4 | 2.4 | 3.2 | 4.7 | 1.1 | .1 | .2 | 15.1 |
| Exploration expenses | | | | | | | | |
| Dry holes | .1 | | | 30.5 | | (.3) | (.5) | 29.8 |
| Geological and geophysical | 17.1 | .5 | | 1.0 | .5 | 3.4 | 3.4 | 25.9 |
| Other | 5.7 | .2 | | .0 | .2 | | 9.3 | 15.4 |
| | 22.9 | .7 | | 31.5 | .7 | 3.1 | 12.2 | 71.1 |
| Undeveloped lease amortization | 31.2 | 14.7 | | | | | 2.5 | 48.4 |

| | | | | | | | | |
|---|---|---|---|---|---|---|---|---|
| Total exploration expenses | 54.1 | 15.4 | | 31.5 | .7 | 3.1 | 14.7 | 119.5 |
| Terra Nova working interest redetermination | | 10.9 | | | | | | 10.9 |
| Selling and general expenses | 13.4 | 6.5 | .4 | .3 | 1.6 | (.6) | 15.2 | 36.8 |
| Results of operations before taxes | 49.7 | 95.5 | 62.4 | 545.9 | 49.8 | 2.5 | (28.1) | 777.7 |
| Income tax provisions | 16.5 | 28.6 | 17.8 | 214.2 | 24.8 | 8.9 | .8 | 311.6 |
| Results of operations (excluding corporate overhead and interest) | $ 33.2 | 66.9 | 44.6 | 331.7 | 25.0 | (6.4) | (28.9) | 466.1 |

*24*

**Table of Contents**

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

**Results of Operations (Contd.)**

*Refining and Marketing*

*Second Quarter 2011 vs 2010*

In 2010, the Company announced its intention to sell its three refineries and U.K. marketing operations during 2011. The Company entered into an agreement to sell the Superior, Wisconsin refinery and associated assets on July 25, 2011. The sale is expected to be completed late in the third quarter or early in the fourth quarter. The sale process for the Meraux, Louisiana refinery and U.K. downstream operations continues to progress. See Note B in the consolidated financial statements for further discussion.

United States Manufacturing operations include two refineries and two ethanol production facilities. United States Marketing includes retail and wholesale fuel marketing operations. Transactions between these two U.S. downstream segments are recorded at agreed market-based transfer prices and eliminations have been made as necessary within the consolidated financial statements. The United Kingdom refining and marketing segment includes the Milford Haven, Wales, refinery and U.K. retail and other refined products marketing operations.

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

| | Income (Loss) | | | |
|---|---|---|---|---|
| | Three Months Ended June 30, | | Six Months Ended June 30, | |
| (Millions of dollars) | 2011 | 2010 | 2011 | 2010 |
| Refining and marketing | | | | |
| United States manufacturing | $ 27.3 | 9.8 | 56.0 | (13.8) |
| United States marketing | 80.2 | 69.6 | 90.9 | 78.5 |
| United Kingdom | (15.8) | 4.4 | (24.5) | (10.6) |
| Total | $ 91.7 | 83.8 | 122.4 | 54.1 |

United States manufacturing operations generated a profit of $27.3 million in the 2011 second quarter compared to a profit of $9.8 million during the second quarter of 2010. The favorable result in 2011 was primarily due to stronger U.S. refining margins, which improved from $0.69 per barrel in the second quarter of 2010 to $2.54 per barrel in the 2011 quarter. Additionally, crude oil feedstock throughput volumes at U.S. refineries were a quarterly record of 170,475 barrels per day during the 2011 quarter. Ethanol production operations were less profitable in 2011 than 2010, primarily due to below break-even results during the operational start-up phase at the Hereford, Texas plant in the second quarter. The ramp-up of production at the Hereford plant has met Company expectations.

United States marketing operations generated income of $80.2 million in the second quarter 2011 compared to income of $69.6 million in the 2010 period. The favorable result in the 2011 quarter was primarily due to an improvement in U.S. retail marketing margins, which totaled $0.199 per gallon in 2011 and $0.162 per gallon in 2010. In addition, these U.S. retail operations generated higher profits from merchandise sales in the 2011 quarter. However, overall per-store retail fuel sales volumes in the current period were below 2010 levels by about 10%.

Refining and marketing operations in the United Kingdom had a loss of $15.8 million in the second quarter of 2011 compared to a profit of $4.4 million in the same quarter of 2010. The U.K. results in 2011 were unfavorably affected by weaker margins during the 2011 quarter. The 2010 period included a $6.0 million benefit from an adjustment of income taxes. Crude oil throughput volumes at the Milford Haven refinery were a quarterly record of 136,428 barrels per day during the 2011 quarter, but throughputs in the 2010 quarter were at significantly lower levels as the plant was shut down for turnaround for a portion of the quarter. The plant came back onstream in May 2010, but experienced inefficient operations upon restart. A capital project completed during the 2010 turnaround expanded the crude oil throughput capacity of the refinery from

108,000 to 135,000 barrels per day.

Worldwide petroleum product sales were 601,498 barrels per day in the 2011 quarter, up from 508,117 barrels per day a year ago. This increase was mostly due to the aforementioned refinery turnaround at Milford Haven during the prior-year second quarter.

**Table of Contents**

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

**Results of Operations (Contd.)**

*Refining and Marketing (Contd.)*

*Six months 2011 vs. 2010*

United States manufacturing operations generated a profit of $56.0 million in the first six months of 2011 compared to a loss of $13.8 million during the 2010 period. The favorable result in 2011 was primarily due to stronger U.S. refining margins, which improved to $2.73 per barrel in 2011 compared to a negative $1.23 per barrel in 2010. Additionally, crude oil throughput volumes at U.S. refineries were 167,753 barrels per day during the 2011 period compared to 125,897 barrels per day in 2010. Lower throughput volumes in 2010 were primarily due to the effects of a six-week complete plant turnaround at the Meraux, Louisiana, refinery during the prior year. Ethanol production operations generated near break-even results in the first six months of 2011, which was below 2010 profit levels. The reduction in 2011 was primarily attributable to unprofitable operations during start-up of the Hereford, Texas, plant during the 2011 second quarter.

United States marketing operations generated income of $90.9 million in the six-month 2011 period, compared to income of $78.5 million in the 2010 period. The favorable result in 2011 was primarily due to U.S. retail marketing margins which improved to $0.146 per gallon in 2011 following a margin of $0.123 per gallon in 2010. In addition, these U.S. retail operations generated higher profits from merchandise sales in 2011. However, overall per-store fuel sales volumes for the retail operations in the 2011 period were below 2010 levels by about 9%.

Refining and marketing operations in the United Kingdom had a loss of $24.5 million in the 2011 six months compared to a loss of $10.6 million in the same 2010 period. The U.K. results in 2011 were hurt by continued weak refining margins. Higher crude oil throughputs at the Milford Haven, Wales, refinery led to larger volumes of products sold into the weak pricing market, generating a larger overall loss in the current year. Crude oil throughput volumes at Milford Haven were 128,919 barrels per day in 2011, up from 53,029 barrels per day in 2010, as the plant was shut down for turnaround for several months in 2010.

Total petroleum product sales were 583,019 barrels per day in the 2011 period, up from 493,486 barrels per day a year ago. This increase was also mostly due to the aforementioned refinery turnarounds at Meraux and Milford Haven during the prior year.

**Table of Contents**

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

**Results of Operations (Contd.)**

Selected operating statistics for the three-month and six-month periods ended June 30, 2010 and 2009 follow.

| | Three Months Ended June 30, | | Six Months Ended June 30, | |
|---|---|---|---|---|
| | 2011 | 2010 | 2011 | 2010 |
| Refinery inputs barrels per day | 314,388 | 207,186 | 304,342 | 188,497 |
| United States | 174,502 | 158,635 | 171,874 | 130,883 |
| Crude oil Meraux, Louisiana | 135,528 | 119,187 | 132,864 | 93,127 |
| Superior, Wisconsin | 34,947 | 33,662 | 34,889 | 32,770 |
| Other feedstocks | 4,027 | 5,786 | 4,121 | 4,986 |
| United Kingdom | 139,886 | 48,551 | 132,468 | 57,614 |
| Crude oil Milford Haven, Wales | 136,428 | 45,104 | 128,919 | 53,029 |
| Other feedstocks | 3,458 | 3,447 | 3,549 | 4,585 |
| Refinery yields barrels per day | 314,388 | 207,186 | 304,342 | 188,497 |
| United States | 174,502 | 158,635 | 171,874 | 130,883 |
| Gasoline | 70,174 | 66,087 | 70,403 | 54,944 |
| Kerosine | 15,098 | 13,484 | 15,289 | 10,493 |
| Diesel and home heating oils | 53,994 | 43,499 | 50,462 | 34,441 |
| Residuals | 17,176 | 22,180 | 16,091 | 18,072 |
| Asphalt | 16,320 | 12,955 | 18,645 | 12,150 |
| Fuel and loss | 1,740 | 430 | 984 | 783 |
| United Kingdom | 139,886 | 48,551 | 132,468 | 57,614 |
| Gasoline | 36,843 | 8,390 | 31,742 | 13,308 |
| Kerosine | 17,937 | 6,843 | 17,043 | 8,323 |
| Diesel and home heating oils | 49,499 | 13,577 | 46,180 | 15,915 |
| Residuals | 14,951 | 3,958 | 13,259 | 5,560 |
| Asphalt | 17,359 | 13,263 | 21,251 | 12,006 |
| Fuel and loss | 3,297 | 2,520 | 2,993 | 2,502 |
| Petroleum products sold barrels per day | 601,498 | 508,117 | 583,019 | 493,486 |
| Total United States | 459,209 | 459,277 | 448,551 | 435,110 |
| United States Manufacturing | 177,878 | 163,113 | 169,851 | 131,673 |
| Gasoline | 81,999 | 73,741 | 80,223 | 62,319 |
| Kerosine | 15,098 | 13,484 | 15,289 | 10,493 |
| Diesel and home heating oils | 53,030 | 43,499 | 50,063 | 34,441 |
| Residuals | 16,926 | 22,523 | 16,080 | 17,965 |
| Asphalt, LPG and other | 10,825 | 9,866 | 8,196 | 6,455 |
| United States Marketing | 431,350 | 426,888 | 424,135 | 410,689 |
| Gasoline | 330,976 | 333,781 | 325,485 | 325,232 |
| Kerosine | 13,768 | 11,766 | 14,886 | 9,487 |
| Diesel and other | 86,606 | 81,341 | 83,764 | 75,970 |
| United States Intercompany Elimination | (150,019) | (130,724) | (145,435) | (107,252) |
| Gasoline | (81,999) | (73,743) | (80,223) | (62,319) |
| Kerosine | (15,098) | (13,482) | (15,289) | (10,492) |
| Diesel and other | (52,922) | (43,499) | (49,923) | (34,441) |
| United Kingdom | 142,289 | 48,840 | 134,468 | 58,376 |
| Gasoline | 39,943 | 15,535 | 33,349 | 16,235 |

| | | | | |
|---|---|---|---|---|
| Kerosine | 16,664 | 6,763 | 16,115 | 8,314 |
| Diesel and home heating oils | 49,859 | 19,034 | 47,305 | 20,358 |
| Residuals | 17,526 | 2,142 | 14,543 | 5,192 |
| LPG and other | 18,297 | 5,366 | 23,156 | 8,277 |
| Unit margins per barrel: | | | | |
| United States refining[1] | $ 2.54 | $ 0.69 | $ 2.73 | $ (1.23) |
| United Kingdom refining and marketing | $ (1.76) | 0.52 | $ (1.22) | (1.65) |
| United States retail marketing: | | | | |
| Fuel margin per gallon[2] | $ 0.199 | $ 0.162 | $ 0.146 | $ 0.123 |
| Gallons sold per store month | 283,111 | 316,378 | 277,658 | 304,294 |
| Merchandise sales revenue per store month | $ 161,722 | $ 158,586 | $ 155,072 | $ 148,576 |
| Merchandise margin as a percentage of merchandise sales | 12.9% | 12.9% | 13.3% | 12.6% |
| Store count at end of period (Company operated) | 1,118 | 1,067 | 1,118 | 1,067 |

1 Represents refinery sales realizations less cost of crude and other feedstocks and refinery operating and depreciation expenses.
2 Represents net sales prices for fuel less purchased cost of fuel.

**Table of Contents**

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

**Results of Operations (Contd.)**

*Corporate*

Corporate activities, which include interest income and expense, foreign exchange effects, and corporate overhead not allocated to operating functions, had net costs of $23.4 million in the 2011 second quarter compared to net costs of $30.6 million in the second quarter of 2010. The 2011 results of corporate activities were favorable to 2010 primarily due to net after-tax gains of $4.9 million on transactions denominated in foreign currencies in the current quarter compared to net after-tax losses of $1.6 million in the comparable 2010 period.

For the first six months of 2011, corporate activities reflected net costs of $45.6 million compared to net costs of $99.0 million a year ago. Six-month corporate costs in 2011 were significantly favorable to 2010 mostly related to the effects of transactions denominated in foreign currencies. Total after-tax gains for foreign currency transactions were $3.9 million in the 2011 period compared to net costs of $42.9 million after taxes in the first six months of 2010. Net interest expense was less in 2011 compared to 2010 due to lower average interest rates on outstanding debt and higher interest capitalized to oil and gas development projects. Administrative expense was higher in 2011 associated with increased employee compensation costs.

**Financial Condition**

Net cash provided by operating activities was $917.9 million for the first six months of 2011 compared to $1,447.7 million during the same period in 2010. Changes in operating working capital other than cash and cash equivalents used cash of $455.7 million in the first six months of 2011, but provided cash of $249.8 million in the first six months of 2010. Cash was used for working capital in 2011 due to an increase in accounts receivable caused by higher sales prices and an increase in crude oil inventories caused by higher volumes held, which were only partially offset by an increase in accounts payable balances. Cash generated from working capital changes in the 2010 period included a $244.4 million recovery of U.S. federal royalties paid in prior years on oil and natural gas production in the Gulf of Mexico. Cash of $754.1 million in the 2011 period and $1,239.3 million in 2010 was generated from maturity of Canadian government securities that had maturity dates greater than 90 days at acquisition. The sale of gas storage assets in Spain in June 2011 generated cash proceeds of $27.4 million.

Significant uses of cash in both years were for dividends, which totaled $106.3 million in 2011 and $95.7 million in 2010, and for property additions and dry holes, which including amounts expensed, were $1,258.7 million and $992.3 million in the six-month periods ended June 30, 2011 and 2010, respectively. Also, the purchase of Canadian government securities with maturity dates greater than 90 days at acquisition used cash of $675.6 million in the 2011 period and $1,263.0 million in the 2010 period. Total accrual basis capital expenditures for continuing operations were as follows:

| | Six Months Ended June 30, | |
|---|---|---|
| (Millions of dollars) | 2011 | 2010 |
| Capital Expenditures | | |
| Exploration and production | $ 1,256.9 | 906.8 |
| Refining and marketing | 88.3 | 189.5 |
| Corporate and other | 3.5 | 3.1 |
| Total capital expenditures | 1,348.7 | 1,099.4 |

A reconciliation of property additions and dry hole costs in the consolidated statements of cash flows to total capital expenditures follows.

Six Months Ended June 30,

| (Millions of dollars) | 2011 | 2010 |
|---|---|---|
| Property additions and dry hole costs per cash flow statements | $ 1,258.7 | 992.3 |
| Geophysical and other exploration expenses | 53.0 | 41.3 |
| Capital expenditure accrual changes | 37.0 | 65.8 |
| Total capital expenditures | 1,348.7 | 1,099.4 |

**Table of Contents**

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

**Financial Condition** ***(Contd.)***

Working capital (total current assets less total current liabilities) at June 30, 2011 was $870.4 million, an increase of $250.7 million from December 31, 2010. This level of working capital does not fully reflect the Company s liquidity position because the lower historical costs assigned to inventories under last-in first-out accounting were $974.3 million below fair value at June 30, 2011. During the second quarter 2011, the Company s $350 million notes maturing in May 2012 were reclassified to a current liability.

At June 30, 2011, long-term notes payable of $1,184.5 million had increased by $245.1 million compared to December 31, 2010. A summary of capital employed at June 30, 2011 and December 31, 2010 follows.

| (Millions of dollars) | June 30, 2011 | | Dec. 31, 2010 | |
|---|---|---|---|---|
| | Amount | % | Amount | % |
| Capital employed | | | | |
| Long-term debt | $ 1,184.5 | 11.8 | 939.4 | 10.3 |
| Stockholders equity | 8,829.2 | 88.2 | 8,199.5 | 89.7 |
| Total capital employed | $ 10,013.7 | 100.0 | 9,138.9 | 100.0 |

The Company s ratio of earnings to fixed charges was 26.9 to 1 for the six-month period ended June 30, 2011.

**Accounting and Other Matters**

The Company adopted new guidance issued by the Financial Accounting Standards Board (FASB) regarding accounting for transfers of financial assets effective January 1, 2010. This guidance makes the concept of a qualifying special-purpose entity as defined previously no longer relevant for accounting purposes. Therefore, formerly qualifying special-purpose entities must be reevaluated for consolidation by reporting entities in accordance with the applicable consolidation guidance. This adoption of this guidance did not have a significant effect on the Company s consolidated financial statements.

The Company adopted, effective January 1, 2010, new guidance issued by the FASB that requires a company to perform an analysis to determine whether its variable interests give it a controlling financial interest in a variable interest entity. The primary beneficiary of a variable interest entity has both the power to direct the activities of the entity that most significantly impact the entity s economic performance and the obligation to absorb potentially significant losses of the entity or the right to receive potentially significant benefits from the entity. A company is required to make ongoing reassessments of whether it is the primary beneficiary of a variable interest entity. This guidance also amended previous guidance for determining whether an entity is considered a variable interest entity. The adoption of this guidance did not have a significant effect on the Company s consolidated financial statements.

In July 2010, the FASB issued new accounting guidance that expanded the disclosure requirements about financing receivables and the related allowance for credit losses. This guidance became effective for the Company at December 31, 2010. Because the Company has no significant financing receivables that extend beyond one year, the impact of this guidance did not have a significant effect on its consolidated financial statement disclosures.

The United States Congress passed the Dodd-Frank Act in 2010. Among other requirements, the law requires companies in the oil and gas industry to disclose payments made to the U.S. Federal and all foreign governments. The SEC was directed to develop the reporting requirements in accordance with the law. The SEC has issued preliminary guidance and has sought feedback thereon from all interested parties. The preliminary rules indicated that payment disclosures would be required at a project level within the annual Form 10-K report beginning with the year ending December 31, 2012. The Company cannot predict the final disclosure requirements that will be required by the Dodd-Frank Act.

**Outlook**

Average crude oil prices in July 2011 were somewhat lower than the average price during the second quarter of 2011. The Company expects its oil and natural gas production to average about 173,000 barrels of oil equivalent per day in the third quarter 2011. U.S. retail marketing margins have fallen significantly in July versus the average margins achieved in the second quarter 2011, while U.S. refining margins have strengthened during July. U.K. downstream margins remain extremely weak early in the third quarter 2011. The Company currently anticipates total capital expenditures for the full year 2011 to be approximately $3.3 billion.

Table of Contents

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

**Forward-Looking Statements**

This Form 10-Q contains forward-looking statements as defined in the Private Securities Litigation Reform Act of 1995. These statements, which express management s current views concerning future events or results, are subject to inherent risks and uncertainties. Factors that could cause actual results to differ materially from those expressed or implied in our forward-looking statements include, but are not limited to, the volatility and level of crude oil and natural gas prices, the level and success rate of our exploration programs, our ability to maintain production rates and replace reserves, customer demand for our products, political and regulatory instability, and uncontrollable natural hazards. For further discussion of risk factors, see Murphy s 2010 Annual Report on Form 10-K on file with the U.S. Securities and Exchange Commission. Murphy undertakes no duty to publicly update or revise any forward-looking statements.

*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 J to this Form 10-Q report, Murphy periodically makes use of derivative financial and commodity instruments to manage risks associated with existing or anticipated transactions. There were short-term commodity derivative contracts in place at June 30, 2011 to hedge the purchase price of about 0.2 million barrels of crude oil and other feedstocks at the Company s refineries. Additionally, there were short-term commodity derivative contracts in place at June 30, 2011 to hedge the purchase price of 10.8 million bushels of corn and to hedge the inventory value of 2.6 million bushels of corn. A 10% increase in the respective benchmark price of these commodities would have reduced the recorded asset associated with these derivative contracts by approximately $5.3 million, while a 10% decrease would have increased the recorded asset by a similar amount. Changes in the fair value of these derivative contracts generally offset the changes in the value for an equivalent volume of these feedstocks.

There were short-term derivative foreign exchange contracts in place at June 30, 2011 to hedge the value of the U.S. dollar against two foreign currencies. A 10% strengthening of the U.S. dollar against these foreign currencies would have reduced the recorded net asset associated with these contracts by approximately $34.0 million, while a 10% weakening of the U.S. dollar would have increased the recorded net asset by approximately $27.8 million. Changes in the fair value of these derivative contracts generally offset the financial statement impact of an equivalent volume of foreign currency exposures associated with other assets and/or liabilities.

*ITEM 4. CONTROLS AND PROCEDURES*

Under the direction of its principal executive officer and principal financial officer, controls and procedures have been established by the Company 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(e) and 15d-15(e) 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 have been no changes in the Company s internal control over financial reporting during the quarter ended June 30, 2011 that have materially affected, or are reasonably likely to materially affect, the Company s internal control over financial reporting.

**Table of Contents**

**PART II OTHER INFORMATION**

***ITEM 1. LEGAL PROCEEDINGS***

Litigation arising out of a June 10, 2003 fire in the Residual Oil Supercritical Extraction (ROSE) unit at the Company s Meraux, Louisiana refinery was settled in July 2009 and memorialized via a filing in the U.S. District Court for the Eastern District of Louisiana on July 24, 2009. An arbitral tribunal heard the Company s claim for indemnity from one of its insurers, AEGIS, in September 2009 and the tribunal ruled in favor of the Company. The Company continues to believe that the ultimate resolution of the June 2003 ROSE fire matter will not have a material adverse effect on its net income, financial condition or liquidity in a future period.

Murphy is engaged in a number of other legal proceedings, all of which Murphy considers routine and incidental to its business. 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 net income, financial condition or liquidity in a future period.

***ITEM 1A. RISK FACTORS***

The Company s operations in the oil and gas business naturally lead to various risks and uncertainties. These risk factors are discussed in Item 1A. Risk Factors in our 2010 Form 10-K filed on February 28, 2011. The Company has not identified any additional risk factors not previously disclosed in its 2010 Form 10-K report.

***ITEM 6. EXHIBITS***

The Exhibit Index on page 33 of this Form 10-Q report lists the exhibits that are hereby filed, incorporated by reference, or furnished with this report.

Table of Contents

**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, Vice President and Controller

*(Chief Accounting Officer and Duly Authorized Officer)*

August 5, 2011

*(Date)*

Table of Contents

**EXHIBIT INDEX**

| Exhibit No. | |
|---|---|
| 12.1* | Computation of Ratio of Earnings to Fixed Charges |
| 31.1* | Certification required by Rule 13a-14(a) pursuant to Section 302 of the Sarbanes-Oxley Act of 2002 |
| 31.2* | Certification required by Rule 13a-14(a) pursuant to Section 302 of the Sarbanes-Oxley Act of 2002 |
| 32 | Certifications pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002 |
| 101. INS | XBRL Instance Document |
| 101. SCH | XBRL Taxonomy Extension Schema Document |
| 101. CAL | XBRL Taxonomy Extension Calculation Linkbase Document |
| 101. DEF | XBRL Taxonomy Extension Definition Linkbase Document |
| 101. LAB | XBRL Taxonomy Extension Labels Linkbase Document |
| 101. PRE | XBRL Taxonomy Extension Presentation Linkbase |

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

Attached as Exhibit 101 to this report are documents formatted in XBRL (Extensible Business Reporting Language). Users of this data are advised pursuant to Rule 406T of Regulation S-T that the interactive data file is deemed not filed or part of a registration statement or prospectus for purposes of section 11 or 12 of the Securities Act of 1933, is deemed not filed for purposes of section 18 of the Securities Exchange Act of 1934, and otherwise not subject to liability under these sections. The financial information contained in the XBRL-related documents is unaudited or unreviewed.

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

*33*