MURPHY OIL CORP /DE
Form 10-Q
August 06, 2013
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UNITED STATES

SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

FORM 10-Q

(Mark one)

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

For the quarterly period ended June 30, 2013

OR

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

For the transition period from _________ to _________

Commission File Number 1-8590

MURPHY OIL CORPORATION

(Exact name of registrant as specified in its charter)

Delaware	**71-0361522**
(State or other jurisdiction of incorporation or organization)	**(I.R.S. Employer Identification Number)**
200 Peach Street 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. x 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). x 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	x	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 x No

Number of shares of Common Stock, $1.00 par value, outstanding at June 30, 2013 was **186,889,023.**

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MURPHY OIL CORPORATION

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PART I FINANCIAL INFORMATION

ITEM 1. FINANCIAL STATEMENTS

Murphy Oil Corporation and Consolidated Subsidiaries

CONSOLIDATED BALANCE SHEETS

(Thousands of dollars)

	(Unaudited) June 30, 2013	December 31, 2012
ASSETS		
Current assets		
Cash and cash equivalents	$ 974,426	947,316
Canadian government securities with maturities greater than 90 days at the date of acquisition	129,884	115,603
Accounts receivable, less allowance for doubtful accounts of $6,491 in 2013 and $6,697 in 2012	2,083,309	1,853,364
Inventories, at lower of cost or market		
Crude oil	186,629	226,541
Finished products	264,947	266,307
Materials and supplies	307,686	259,462
Prepaid expenses	404,255	335,831
Deferred income taxes	64,577	89,040
Assets held for sale	0	15,119
Total current assets	4,415,713	4,108,583
Property, plant and equipment, at cost less accumulated depreciation, depletion and amortization of $8,794,519 in 2013 and $8,138,587 in 2012	14,233,376	13,011,606
Goodwill	40,652	43,103
Deferred charges and other assets	135,234	151,183
Assets held for sale	0	208,168
Total assets	$ 18,824,975	17,522,643
LIABILITIES AND STOCKHOLDERS EQUITY		
Current liabilities		
Current maturities of long-term debt	$ 17,575	46
Accounts payable and accrued liabilities	3,341,504	3,141,717
Income taxes payable	393,228	219,847
Liabilities associated with assets held for sale	0	47,471
Total current liabilities	3,752,307	3,409,081
Long-term debt	3,046,062	2,245,201
Deferred income taxes	1,557,744	1,544,336
Asset retirement obligations	819,970	724,273
Deferred credits and other liabilities	514,720	516,540
Liabilities associated with assets held for sale	0	141,177
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 194,770,571 shares in 2013 and 194,616,470 shares in 2012	194,771	194,616
Capital in excess of par value	881,617	873,934
Retained earnings	8,361,256	7,717,389

Accumulated other comprehensive income	182,133	408,901
Treasury stock, 7,881,548 shares of Common Stock in 2013 and 3,975,153 shares of Common Stock in 2012, at cost	(485,605)	(252,805)
Total stockholders equity	9,134,172	8,942,035
Total liabilities and stockholders equity	$ 18,824,975	17,522,643

See Notes to Consolidated Financial Statements, page 7.

The Exhibit Index is on page 36.

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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,	
	2013	2012*	2013	2012*
REVENUES				
Sales and other operating revenues	$ 7,201,508	7,146,728	13,849,452	14,100,501
Gain (loss) on sale of assets	(318)	35	(278)	125
Interest and other income	16,652	10,842	8,622	13,915
Total revenues	7,217,842	7,157,605	13,857,796	14,114,541
COSTS AND EXPENSES				
Crude oil and product purchases	5,452,526	5,631,306	10,452,171	11,145,685
Operating expenses	526,142	532,374	1,125,244	1,020,859
Exploration expenses, including undeveloped lease amortization	88,772	96,724	197,265	149,651
Selling and general expenses	115,267	87,619	225,009	175,778
Depreciation, depletion and amortization	412,288	309,822	806,042	642,410
Impairment of assets	21,587	0	21,587	0
Accretion of asset retirement obligations	12,239	9,601	24,404	19,047
Interest expense	29,593	11,598	56,621	23,337
Interest capitalized	(14,478)	(9,476)	(27,866)	(15,899)
Total costs and expenses	6,643,936	6,669,568	12,880,477	13,160,868
Income from continuing operations before income taxes	573,906	488,037	977,319	953,673
Income tax expense	241,778	196,731	437,221	380,929
Income from continuing operations	332,128	291,306	540,098	572,744
Income from discontinued operations, net of taxes	70,516	4,131	223,145	12,764
NET INCOME	$ 402,644	295,437	763,243	585,508
PER COMMON SHARE BASIC				
Income from continuing operations	$ 1.76	1.50	2.85	2.95
Income from discontinued operations	0.37	0.02	1.17	0.07
Net income	$ 2.13	1.52	4.02	3.02
PER COMMON SHARE DILUTED				
Income from continuing operations	$ 1.75	1.50	2.83	2.94
Income from discontinued operations	0.37	0.02	1.17	0.07
Net income	$ 2.12	1.52	4.00	3.01
Average common shares outstanding				
Basic	189,002,146	194,208,795	189,753,673	194,050,950
Diluted	189,944,793	194,846,202	190,702,248	194,820,285

* Reclassified to conform to current presentation.
See Notes to Consolidated Financial Statements, page 7.

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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,	
	2013	2012	2013	2012
Net income	$ 402,644	295,437	763,243	585,508
Other comprehensive income (loss), net of tax				
Net gain (loss) from foreign currency translation	(117,254)	(66,550)	(235,008)	15,702
Retirement and postretirement benefit plans	4,532	2,964	7,270	5,672
Deferred loss on interest rate hedges:				
Reduction of deferred loss on interest rate hedge	0	(5,390)	0	(2,407)
Amount of loss reclassified to interest expense in consolidated statements of income	484	240	970	240
Other comprehensive income (loss)	(112,238)	(68,736)	(226,768)	19,207
COMPREHENSIVE INCOME	$ 290,406	226,701	536,475	604,715

See Notes to Consolidated Financial Statements, page 7.

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Murphy Oil Corporation and Consolidated Subsidiaries

CONSOLIDATED STATEMENTS OF CASH FLOWS (unaudited)

(Thousands of dollars)

	Six Months Ended June 30, 2013	Six Months Ended June 30, 2012[1]
OPERATING ACTIVITIES		
Net income	$ 763,243	585,508
Adjustments to reconcile net income to net cash provided by operating activities		
Income from discontinued operations	(223,145)	(12,764)
Depreciation, depletion and amortization	806,042	642,410
Impairment of assets	21,587	0
Amortization of deferred major repair costs	12,991	10,949
Expenditures for asset retirements	(20,124)	(12,763)
Dry hole costs	81,305	34,217
Amortization of undeveloped leases	32,052	75,072
Accretion of asset retirement obligations	24,404	19,047
Deferred and noncurrent income tax charges	65,333	43,945
Pretax (gain) loss from disposition of assets	278	(125)
Net (increase) decrease in noncash operating working capital	65,144	(103,345)
Other operating activities, net	24,172	32,086
Net cash provided by continuing operations	1,653,282	1,314,237
Net cash provided by discontinued operations	15,728	32,881
Net cash provided by operating activities	1,669,010	1,347,118
INVESTING ACTIVITIES		
Property additions and dry hole costs[2]	(1,963,618)	(1,314,589)
Proceeds from sales of assets	169	163
Purchase of investment securities[3]	(373,196)	(836,472)
Proceeds from maturity of investment securities[3]	358,915	897,793
Expenditures for major repairs	(7,682)	(7,440)
Investing activities of discontinued operations		
Sales proceeds	282,202	0
Property additions and other	(8,109)	(22,430)
Other net	4,379	5,872
Net cash required by investing activities	(1,706,940)	(1,277,103)
FINANCING ACTIVITIES		
Borrowings of long-term debt[2]	461,978	541,896
Maturities of notes payable	0	(350,000)
Purchase of treasury stock	(250,000)	0
Proceeds from exercise of stock options and employee stock purchase plans	2,628	8,752
Excess tax benefits related to exercise of stock options	69	1,328
Withholding tax on stock-based incentive awards	(8,966)	(3,703)
Issue cost of notes payable and debt facility	(2,793)	(3,943)
Cash dividends paid	(119,376)	(106,797)
Net cash provided by financing activities	83,540	87,533

Effect of exchange rate changes on cash and cash equivalents	(18,500)	221
Net increase in cash and cash equivalents	27,110	157,769
Cash and cash equivalents at January 1	947,316	513,873
Cash and cash equivalents at June 30	$ 974,426	671,642

[1] Reclassified to conform to current presentation.

[2] Excludes non-cash asset and long-term obligation of $356,170 in 2013 associated with lease commencement for production equipment at the Kakap field offshore Malaysia.

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

See Notes to Consolidated Financial Statements, page 7.

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Murphy Oil Corporation and Consolidated Subsidiaries

CONSOLIDATED STATEMENTS OF STOCKHOLDERS EQUITY (unaudited)

(Thousands of dollars)

	Six Months Ended June 30, 2013	2012
Cumulative Preferred Stock par $100, authorized 400,000 shares, none issued	0	0
Common Stock par $1.00, authorized 450,000,000 shares, issued 194,770,571 shares at June 30, 2013 and 194,380,426 shares at June 30, 2012		
Balance at beginning of period	$ 194,616	193,909
Exercise of stock options	155	247
Awarded restricted stock	0	224
Balance at end of period	194,771	194,380
Capital in Excess of Par Value		
Balance at beginning of period	873,934	817,974
Exercise of stock options, including income tax benefits	1,928	9,036
Restricted stock transactions and other	(24,485)	(5,257)
Stock-based compensation	30,327	20,886
Sale of stock under employee stock purchase plans	0	1,554
Other	(87)	0
Balance at end of period	881,617	844,193
Retained Earnings		
Balance at beginning of period	7,717,389	7,460,942
Net income for the period	763,243	585,508
Cash dividends	(119,376)	(106,797)
Balance at end of period	8,361,256	7,939,653
Accumulated Other Comprehensive Income		
Balance at beginning of period	408,901	310,420
Foreign currency translation gain (loss), net of income taxes	(235,008)	15,702
Retirement and postretirement benefit plans, net of income taxes	7,270	5,672
Change in deferred loss on interest rate hedges, net of income taxes	970	(2,167)
Balance at end of period	182,133	329,627
Treasury Stock		
Balance at beginning of period	(252,805)	(4,848)
Purchase of treasury shares	(250,000)	0
Sale of stock under employee stock purchase plans	655	1,623
Awarded restricted stock, net of forfeitures	16,545	0
Balance at end of period	(485,605)	(3,225)
Total Stockholders Equity	$ 9,134,172	9,304,628

See notes to Consolidated Financial Statements, page 7

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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, 2012. 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, 2013, and the results of operations, cash flows and changes in stockholders equity for the three-month and six-month periods ended June 30, 2013 and 2012, 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 2012 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, 2013 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, 2013, the Company had total capitalized exploratory well costs pending the determination of proved reserves of $444.4 million. The following table reflects the net changes in capitalized exploratory well costs during the six-month periods ended June 30, 2013 and 2012.

(Thousands of dollars)	2013	2012
Beginning balance at January 1	$ 445,697	556,412
Additions pending the determination of proved reserves	27,129	85,851
Reclassifications to proved properties based on the determination of proved reserves	(28,398)	(42,431)
Capitalized exploratory well costs charged to expense	0	(32,187)
Balance at June 30	$ 444,428	567,645

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,					
	2013			2012		
(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	$ 49,994	3	1	$ 103,807	36	6
One to two years	37,898	5	1	103,141	15	3
Two to three years	73,863	7	3	67,197	9	2
Three years or more	282,673	26	5	293,500	37	5

$ 444,428	41	10	$ 567,645	97	16

Of the $394.4 million of exploratory well costs capitalized more than one year at June 30, 2013, $273.0 million is in Malaysia, $114.8 million is in the U.S. and $6.6 million is in Brunei. 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 Brunei field development plans are being prepared by the operator.

See also Note E for discussion regarding a capital lease of production equipment at the Kakap field.

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Contd.)

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, 2013 and December 31, 2012, the carrying value of inventories under the LIFO method was $553.4 million and $571.2 million, respectively, less than such inventories would have been valued using the first-in, first-out (FIFO) method.

Note D Discontinued Operations

The Company sold its oil and gas assets in the United Kingdom during 2013. After-tax gains on sale of the assets were $68.8 million in the three months ended June 30, 2013 and $216.2 million in the six-months ended June 30, 2013. The Company has accounted for these U.K. upstream operations as discontinued operations in its consolidated financial statements for all periods presented.

The results of operations associated with these discontinued operations for the three-month and six-month periods ended June 30, 2013 and 2012 were as follows:

	Three-Months Ended June 30,		Six-Months Ended June 30,	
(Thousands of dollars)	2013	2012	2013	2012
Revenues	$ 78,189	32,734	244,711	70,317
Income before income taxes, including pretax gain on disposals of $55,640 and $130,568 during the three-month and six-month periods in 2013	64,667	11,727	154,188	34,700
Income tax expense (benefit)	(5,849)	7,596	(68,957)	21,936

The Company has previously announced that its Board of Directors had approved a plan to separate its U.S. retail marketing business into a separate publicly owned company. The Company has also announced that its Board of Directors had approved plans to exit the U.K. refining and marketing business. These operations are presented as the U.S. and U.K. refining and marketing segments in Note P. The separation of the U.S. retail marketing business is expected to be completed during 2013. The sale process for the U.K. downstream assets continues in 2013. Based on current market conditions, it is possible that the Company could incur a loss when the U.K. downstream assets are sold. If the separation of the U.S. retail marketing business and the sale of the U.K. downstream assets continue to progress, the results of these operations are likely to be presented as discontinued operations in future periods when the operations no longer qualify as continuing operations under U.S. generally accepted accounting principles.

Note E Financing Arrangements and Debt

In May 2013, the Company increased the capacity of its committed credit facility to $2.0 billion, and it extended the facility for one year such that it now expires in June 2017. Borrowings under the facility continue to bear interest at 1.25% above LIBOR based on the Company s current credit rating as of June 30, 2013. In addition, facility fees of 0.25% are charged on the full $2.0 billion commitment. The Company also has a 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 October 2015.

During June 2013, the Company and its partners entered into a 25-year lease of production equipment at the Kakap field offshore Malaysia. The lease has been accounted for as a capital lease, and payments under the agreement are to be made over a 15-year period through June 2028. The original lease asset, which was recorded in Property, Plant and Equipment, and the associated debt obligation, which was recorded in Current Maturities of Long-Term Debt and Long-Term Debt, amounted to $356.2 million.

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Contd.)

Note F Cash Flow Disclosures

Additional disclosures regarding cash flow activities are provided below.

(Thousands of dollars)	Six Months Ended June 30, 2013	2012
Net (increase) decrease in operating working capital other than cash and cash equivalents:		
(Increase) decrease in accounts receivable	$ (219,802)	292,226
Increase in inventories	(2,313)	(96,612)
Increase in prepaid expenses	(116,276)	(118,139)
Decrease in deferred income tax assets	72,652	22,690
Increase (decrease) in accounts payable and accrued liabilities	182,903	(248,040)
Increase in current income tax liabilities	147,980	44,530
Total	$ 65,144	(103,345)
Supplementary disclosures:		
Cash income taxes paid	$ 196,923	326,727
Interest paid, net of amounts capitalized	25,010	8,657

Note G 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 active and retired U.S. employees. Additionally, most U.S. retired employees are covered by a life insurance benefit plan. The health care benefits are contributory; the life insurance benefits are noncontributory.

The table that follows provides the components of net periodic benefit expense for the three-month and six-month periods ended June 30, 2013 and 2012.

	Three Months Ended June 30,			
	Pension Benefits		Other Postretirement Benefits	
(Thousands of dollars)	2013	2012	2013	2012
Service cost	$ 7,094	6,035	1,230	1,049
Interest cost	7,700	7,545	1,279	1,342
Expected return on plan assets	(7,569)	(6,520)	0	0
Amortization of prior service cost	303	313	(44)	(43)
Amortization of transitional asset	121	116	2	2
Recognized actuarial loss	4,759	3,847	473	452
Special termination benefits	0	6,170	0	0
Net periodic benefit expense	$ 12,408	17,506	2,940	2,802

	Six Months Ended June 30,			
	Pension Benefits		Other Postretirement Benefits	
(Thousands of dollars)	2013	2012	2013	2012
Service cost	$ 14,697	11,923	2,397	2,090
Interest cost	14,131	14,837	2,513	2,791
Expected return on plan assets	(13,269)	(12,825)	0	0
Amortization of prior service cost	579	625	(86)	(89)
Amortization of transitional asset	241	227	4	4
Recognized actuarial loss	8,291	7,614	930	941
Special termination benefits	0	6,170	0	0
Net periodic benefit expense	$ 24,670	28,571	5,758	5,737

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Contd.)

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

During the six-month period ended June 30, 2013, the Company made contributions of $27.5 million to its defined benefit pension and postretirement benefit plans. Remaining funding in 2013 for the Company s defined benefit pension and postretirement plans is anticipated to be $21.0 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) eliminated 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 eligible U.S. retired employees. The law did not significantly affect the Company s Consolidated Balance Sheets as of June 30, 2013 and December 31, 2012 and the Consolidated Statements of Income for the three-month and six-month periods ended June 30, 2013 and 2012. 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 information available 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 H Incentive Plans

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

The 2012 Annual Incentive Plan (2012 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 2012 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 2012 Long-Term Incentive Plan (2012 Long-Term Plan) authorizes the Committee to make grants of the Company s Common Stock and other stock-based incentives 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 2012 Long-Term Plan expires in 2022. A total of 8,700,000 shares are issuable during the life of the 2012 Long-Term Plan, with annual grants limited to 1% of 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.

During 2013, the Committee has granted stock options for 1,163,300 shares at exercise prices ranging between $60.15 and $60.585 per share. The Black-Scholes valuation for these awards was $15.81 per option. The Committee also granted 455,700 performance-based restricted stock units during the first six months of 2013. The fair value of the performance-based restricted stock units, using a Monte Carlo valuation model, ranged from $39.50 to $54.82 per unit. Additionally, on February 5, 2013, the Committee granted 851,000 stock appreciation rights (SAR) and 93,200 units of restricted stock-cash (RSU-C) to certain employees. The SAR and RSU-C are to be settled in cash, net of applicable income taxes, and are accounted for as liability-type awards. The initial fair values of these SAR were equivalent to the stock options granted, while the initial value of RSU-C were equivalent to restricted stock units granted. On February 6, 2013, the Committee granted 36,600 shares of time-based restricted stock units 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 $60.30 per share.

Cash received from options exercised under all share-based payment arrangements for the six-month periods ended June 30, 2013 and 2012 was $2.6 million and $8.8 million, respectively. The actual income tax benefit realized for the tax deductions from option exercises of the share-based payment arrangements totaled $3.0 million and $2.4 million for the six-month periods ended June 30, 2013 and 2012, respectively.

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Contd.)

Note H Incentive Plans *(Contd.)*

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

	Six Months Ended June 30,	
(Thousands of dollars)	2013	2012
Compensation charged against income before tax benefit	$ 35,142	20,994
Related income tax benefit recognized in income	7,246	6,453

Note I 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, 2013 and 2012. 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)	2013	2012	2013	2012
Basic method	189,002,146	194,208,795	189,753,673	194,050,950
Dilutive stock options and restricted stock units	942,647	637,407	948,575	769,335
Diluted method	189,944,793	194,846,202	190,702,248	194,820,285

The following table reflects certain options to purchase shares of common stock that were outstanding during the 2013 and 2012 periods but were not included in the computation of diluted EPS above because the incremental shares from assumed conversion were antidilutive.

	Three Months Ended June 30,		Six Months Ended June 30,	
	2013	2012	2013	2012
Antidilutive stock options excluded from diluted shares	1,731,425	3,621,562	1,414,286	3,169,055
Weighted average price of these options	$ 63.52	$ 64.69	$ 64.39	$ 65.57

Note J 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 2013 and 2012, the Company s effective income tax rates were as follows:

	2013	2012
Three months ended June 30	42.1%	40.3%
Six months ended June 30	44.7%	39.9%

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, certain of which have income tax rates that are higher than the U.S. Federal rate; 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 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, 2013, the earliest years remaining open for audit and/or settlement in our major taxing jurisdictions are as follows: United States 2009; Canada 2007; United Kingdom 2011; and Malaysia 2006.

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Contd.)

Note K Financial Instruments and Risk Management

Murphy periodically utilizes derivative instruments to manage certain risks related to commodity prices, foreign currency exchange rates and interest 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 commodity and foreign currency derivative contracts as hedges, and therefore, it recognizes all gains and losses on these derivative contracts in its Consolidated Statements of Income. Certain interest rate derivative contracts are accounted for as hedges and the gain or loss associated with recording the fair value of these contracts has been deferred in Accumulated Other Comprehensive Income until the anticipated transactions occur.

Commodity Purchase Price Risks

The Company is subject to commodity price risk related to corn that it will purchase in the future for feedstock and to wet and dried distillers grain with solubles that it will sell in the future at its ethanol production facilities in the United States. At June 30, 2013 and 2012, the Company had open physical delivery commitment contracts for purchase of approximately 17.2 million and 23.6 million bushels of corn, respectively, for processing at its ethanol plants. For the periods ending June 30, 2013 and 2012, the Company had open physical delivery commitment contracts for sale of approximately 1.4 million and 0.9 million equivalent bushels, respectively, of wet and dried distillers grain with solubles. To manage the price risk associated with certain of these physical delivery commitments which have fixed prices, at June 30, 2013 and 2012, the Company had outstanding derivative contracts with a net volume of approximately 13.4 million and 20.4 million bushels, respectively, that mature at future prices in effect on the expected date of delivery under the physical delivery commitment contracts. Additionally, at June 30, 2013 and 2012, the Company had outstanding derivative contracts to sell 2.3 million and 3.2 million bushels of corn, respectively, and buy them back when certain corn inventories are expected to be processed at the Hankinson, North Dakota, and Hereford, Texas facilities. The impact of marking to market these commodity derivative contracts increased income before taxes by $1.5 million and reduced income before taxes by $0.3 million for the six months ended June 30, 2013 and 2012, respectively.

Foreign Currency Exchange Risks

The Company is subject to foreign currency exchange risk associated with operations in countries outside the United States. Short-term derivative instruments were outstanding at June 30, 2013 and 2012 to manage the risk of certain future income taxes that are payable in Malaysian ringgits. The equivalent U.S. dollars of Malaysian ringgit derivative contracts open at June 30, 2013 and 2012 were approximately $153.4 million and $235.6 million, respectively. Short-term derivative instrument contracts totaling $48.0 million and $13.0 million U.S. dollars were also outstanding at June 30, 2013 and 2012, 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 reduced income before taxes by $5.6 million for the six-month period ended June 30, 2013 and increased income before taxes by $9.2 million for the six-month period ended June 30, 2012.

At June 30, 2013 and December 31, 2012, the fair value of derivative instruments not designated as hedging instruments are presented in the following table.

	June 30, 2013		December 31, 2012	
(Thousands of dollars)	Asset (Liability) Derivatives		Asset (Liability) Derivatives	
Type of Derivative Contract	Balance Sheet Location	Fair Value	Balance Sheet Location	Fair Value
Commodity	Accounts receivable	$ 6,088	Accounts receivable	$ 3,043
Commodity	Accounts payable	(4,552)	Accounts payable	(102)
Foreign exchange	Accounts payable	(5,551)	Accounts payable	(1,031)

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Contd.)

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

For the three-month and six-month periods ended June 30, 2013 and 2012, 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.

		Gain (Loss)			
		Three Months Ended June 30,		Six Months Ended June 30,	
(Thousands of dollars) Type of Derivative Contract	Statement of Income Location	2013	2012	2013	2012
Commodity	Crude oil and product purchases	$ 2,834	1,618	(1,376)	2,263
Foreign exchange	Interest and other income	(1,328)	(8,318)	(4,146)	9,197
		$ 1,506	(6,700)	(5,522)	11,460

Interest Rate Risks

The Company had ten-year notes totaling $350 million that matured on May 1, 2012. The Company expected to replace these notes at maturity with new ten-year notes, and it therefore had risk associated with the interest rate related to the anticipated sale of these notes in 2012. To manage this risk, in 2011 the Company entered into a series of derivative contracts known as forward starting interest rate swaps that matured in May 2012. The Company utilized hedge accounting to defer any gain or loss on these contracts associated with the payment of interest on these anticipated notes in 2012 through 2022. During the six-month periods ended June 30, 2013 and 2012, $1.5 million and $0.8 million, respectively, of the deferred loss on the interest rate swaps were charged to income. The remaining loss deferred on these matured contracts at June 30, 2013 was $26.3 million, which is recorded, net of income taxes of $9.2 million, in Accumulated Other Comprehensive Income in the Consolidated Balance Sheet. The Company expects to charge approximately $1.5 million of this deferred loss to income in the form of interest expense during the remaining six months of 2013.

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, 2013 and December 31, 2012 are presented in the following table.

	June 30, 2013				December 31, 2012			
(Thousands of dollars)	Level 1	Level 2	Level 3	Total	Level 1	Level 2	Level 3	Total
Assets								
Commodity derivative contracts	$ 0	6,088	0	6,088	0	3,043	0	3,043
Liabilities								
Nonqualified employee savings plans	$ (11,203)	0	0	(11,203)	(10,293)	0	0	(10,293)
Commodity derivative contracts	0	(4,552)	0	(4,552)	0	(102)	0	(102)

Foreign currency exchange derivative contracts	0	(5,551)	0	(5,551)	0	(1,031)	0	(1,031)
	$ (11,203)	(10,103)	0	(21,306)	(10,293)	(1,133)	0	(11,426)

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Contd.)

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

The fair value of commodity derivative contracts for corn and wet and dried distillers grain was determined based on market quotes 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 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 the nonqualified employee savings plan is recorded in Selling and General Expenses.

The Company offsets certain assets and liabilities related to derivative contracts when the legal right of offset exists. Derivative assets and liabilities which have offsetting positions at June 30, 2013 and December 31, 2012 are presented in the following tables.

(Thousands of dollars)	Gross Amounts of Recognized Assets	Gross Amounts Offset in the Consolidated Balance Sheet	Net Amounts of Assets Presented in the Consolidated Balance Sheet
At June 30, 2013			
Commodity derivatives	$ 6,203	(115)	6,088
At December 31, 2012			
Commodity derivatives	$ 3,111	(2,169)	942

(Thousands of dollars)	Gross Amounts of Recognized Liabilities	Gross Amounts Offset in the Consolidated Balance Sheet	Net Amounts of Liabilities Presented in the Consolidated Balance Sheet
At June 30, 2013			
Commodity derivatives	$ 4,667	(115)	4,552
At December 31, 2012			
Commodity derivatives	$ 2,271	(2,169)	102

All commodity derivatives above are corn-based contracts associated with the Company s two U.S. ethanol plants. Net derivative assets in the table above are included in Accounts Receivable presented in the table on page 12 and are included in Accounts Receivable on the Consolidated Balance Sheet; likewise, net derivative liabilities in the above table are included in Accounts Payable in the table on page 12 and are included in Accounts Payable and Accrued Liabilities on the Consolidated Balance Sheet. Separate derivative agreements exist for each of the ethanol plants. These contracts permit net settlement and the Company generally avails itself of this right to settle net. At June 30, 2013 cash deposits of $12.3 million related to commodity derivative contracts were reported in Prepaid Expenses in the Consolidated Balance Sheet. These cash deposits have not been used to reduce the reported net liability on the corn-based derivative contracts at June 30, 2013.

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Contd.)

Note L Accumulated Other Comprehensive Income

The components of Accumulated Other Comprehensive Income (AOCI) on the Consolidated Balance Sheets at March 31, 2013 and June 30, 2013 and the changes during the three month periods ended March 31, 2013 and June 30, 2013 are presented net of taxes in the following table.

(Thousands of dollars)	Foreign Currency Translation Gains (Losses)[1]	Retirement and Postretirement Benefit Plan Adjustments[1]	Deferred Loss on Interest Rate Derivative Hedges[1]	Total[1]
Balance at January 1, 2013	613,492	(186,539)	(18,052)	408,901
Components of other comprehensive income (loss):				
Before reclassifications to income	(117,754)	207	0	(117,547)
Reclassifications to income	0	2,531[2]	486[3]	3,017
Net other comprehensive income (loss)	(117,754)	2,738	486	(114,530)
Balance at March 31, 2013	495,738	(183,801)	(17,566)	294,371
Components of other comprehensive income (loss):				
Before reclassifications to income	(117,254)	242	0	(117,012)
Reclassification to income	0	4,290[2]	484[3]	4,774
Net other comprehensive income (loss)	(117,254)	4,532	484	(112,238)
Balance at June 30, 2013	378,484	(179,269)	(17,082)	182,133

1 All amounts are presented net of income taxes.

2 Reclassifications before taxes of $4,850 and $5,704 for the three-month periods ended March 31, 2013 and June 30, 2013, respectively, are included in the computation of net periodic benefit expense. See Note G for additional information. Related income taxes of $2,319 and $1,414 for the three-month periods ended March 31, 2013 and June 30, 2013, respectively, are included in Income tax expense.

3 Reclassifications before taxes of $741 for each of the three-month periods ended March 31, 2013 and June 30, 2013 are included in Interest expense. Related income taxes of $255 and $257 for the three-month periods ended March 31, 2013 and June 30, 2013, respectively, are included in Income tax expense.

Note M 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.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Contd.)

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

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. With the sale of the U.S. refineries in 2011, the Company retained certain liabilities related to environmental matters at these sites. The Company also has insurance covering certain levels of environmental expenses at the refinery sites. The Company 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 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 the 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 this 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.

Murphy and its subsidiaries are 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, 2013, the Company had contingent liabilities of $112.7 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 N Accounting Matters

In December 2011, the Financial Accounting Standards Board (FASB) issued an accounting standards update that requires enhanced disclosures about financial instruments and derivative instruments that are either offset in the balance sheet or are subject to an enforceable master netting arrangement or similar agreement. The guidance was effective for all interim and annual periods beginning on or after January 1, 2013. These disclosures are presented in Note K.

In February 2013, the FASB issued an accounting standards update that requires additional disclosures for reclassification adjustments from accumulated other comprehensive income (AOCI). These additional disclosures include changes in AOCI balances by component and significant items reclassified out of AOCI. These disclosures must be presented either on the face of the affected financial statement or in the notes to the financial statements. The disclosures are effective for Murphy Oil beginning in the first quarter of 2013 and are to be provided on a prospective basis. These disclosures are presented in Note L.

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Contd.)

Note O Commitments

The Company has entered into forward sales contracts to mitigate the price risk for a portion of its 2013 heavy oil and 2013 and 2014 natural gas sales volumes in Western Canada. The heavy oil sales contracts call for deliveries of 4,000 barrels per day in July through September 2013 that achieve netback values ranging from US$50.42 to US$56.43 per barrel. The natural gas contracts call for deliveries between April through December 2013 that average approximately 77 million cubic feet per day at prices ranging from Cdn$3.69 to Cdn$3.87 per MCF, with the contracts calling for delivery at the NOVA inventory transfer sales point. Additionally for 2014, open gas contracts call for deliveries of 50 million cubic feet per day at an average price of Cdn$4.01 per MCF. These oil and natural gas contracts have been accounted for as normal sales for accounting purposes.

In July 2013, the Company entered into a series of West Texas Intermediate crude oil price swap financial contracts to hedge 10,000 barrels per day of Eagle Ford Shale production from August 2013 through June 2014. Under these contracts, which mature monthly, the Company will pay the average monthly price in effect and will receive the fixed contract price. The average fixed prices for these contracts are $101.55 per barrel for the 2013 contracts, $96.71 per barrel for the January through March 2014 contracts, and $95.70 per barrel for the April through June 2014 contracts. The Company will use mark-to-market accounting for these contracts through the various maturity dates.

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Contd.)

Note P Business Segments

(Millions of dollars)	Total Assets at June 30, 2013	Three Months Ended June 30, 2013 External Revenues	Three Months Ended June 30, 2013 Income (Loss)	Three Months Ended June 30, 2012 External Revenues	Three Months Ended June 30, 2012 Income (Loss)
Exploration and production*					
United States	$ 4,331.4	444.2	122.9	201.7	(1.2)
Canada	4,258.3	316.8	51.7	264.9	43.7
Malaysia	5,709.7	554.7	213.5	611.3	223.2
Republic of the Congo	68.0	0.0	(11.7)	0.0	(5.3)
Other	94.1	(0.4)	(86.2)	0.1	(34.4)
Total	14,461.5	1,315.3	290.2	1,078.0	226.0
Refining and marketing					
United States	1,832.3	4,458.3	77.9	4,512.1	73.3
United Kingdom	1,133.2	1,427.6	(5.7)	1,556.7	7.2
Total	2,965.5	5,885.9	72.2	6,068.8	80.5
Total operating segments	17,427.0	7,201.2	362.4	7,146.8	306.5
Corporate	1,393.9	16.6	(30.3)	10.8	(15.2)
Assets/revenue/income from continuing operations	18,820.9	7,217.8	332.1	7,157.6	291.3
Discontinued operations, net of tax	4.1	0.0	70.5	0.0	4.1
Total	$ 18,825.0	7,217.8	402.6	7,157.6	295.4

(Millions of dollars)	Six Months Ended June 30, 2013 External Revenues	Six Months Ended June 30, 2013 Income (Loss)	Six Months Ended June 30, 2012 External Revenues	Six Months Ended June 30, 2012 Income (Loss)
Exploration and production*				
United States	$ 853.1	216.7	422.8	49.6
Canada	577.6	65.0	571.9	117.0
Malaysia	1,114.7	418.7	1,175.3	447.2
Republic of the Congo	69.5	(26.5)	57.6	(3.7)
Other	(0.6)	(151.8)	0.1	(71.2)
Total	2,614.3	522.1	2,227.7	538.9
Refining and marketing				
United States	8,477.8	107.3	8,776.3	66.1
United Kingdom	2,757.1	(9.8)	3,096.7	10.2
Total	11,234.9	97.5	11,873.0	76.3

Total operating segments	13,849.2	619.6	14,100.7	615.2
Corporate	8.6	(79.5)	13.8	(42.5)
Revenue/income from continuing operations	13,857.8	540.1	14,114.5	572.7
Discontinued operations, net of tax	0.0	223.1	0.0	12.8
Total	$ 13,857.8	763.2	14,114.5	585.5

* Additional details about results of oil and gas operations are presented in the tables on pages 24 and 25.

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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 2013 was $402.6 million ($2.12 per diluted share) compared to net income of $295.4 million ($1.52 per diluted share) in the second quarter of 2012. The 2013 second quarter included income from discontinued operations of $70.5 million ($0.37 per diluted share) related to oil and gas assets in the U.K., all of which were sold during the first six months of 2013. Income from continuing operations increased from $291.3 million ($1.50 per diluted share) in the 2012 quarter to $332.1 million ($1.75 per diluted share) in 2013. The income improvement from continuing operations in 2013 primarily related to higher earnings in the U.S. oil and gas business due to significantly higher oil production volumes in the Eagle Ford Shale area of South Texas during the just completed quarter.

For the first six months of 2013, net income totaled $763.2 million ($4.00 per diluted share) compared to net income of $585.5 million ($3.01 per diluted share) for the same period in 2012. Earnings in the first six months of 2013 included income from discontinued operations of $223.1 million ($1.17 per diluted share) up from $12.8 million ($0.07 per diluted share in the 2012 period. Continuing operations earned $540.1 million ($2.83 per diluted share) in the first six months of 2013, down from $572.7 million ($2.94 per diluted share) in the 2012 period. The reduction in income from continuing operations in 2013 compared to 2012 was primarily attributable to higher expenses associated with exploration, administration and long-term financing in the most recent period.

Murphy s income by operating business is presented below.

	Income (Loss)			
	Three Months Ended June 30,		Six Months Ended June 30,	
(Millions of dollars)	2013	2012	2013	2012
Exploration and production	$ 290.2	226.0	522.1	538.9
Refining and marketing	72.2	80.5	97.5	76.3
Corporate	(30.3)	(15.2)	(79.5)	(42.5)
Income from continuing operations	332.1	291.3	540.1	572.7
Discontinued operations	70.5	4.1	223.1	12.8
Net income	$ 402.6	295.4	763.2	585.5

In the 2013 second quarter, the Company s exploration and production continuing operations earned $290.2 million compared to $226.0 million in the 2012 quarter. Income in the 2013 quarter was favorably impacted compared to 2012 by higher worldwide crude oil sales volumes. The Company s refining and marketing operations generated income of $72.2 million in the 2013 second quarter compared to income of $80.5 million in the same quarter of 2012. U.K. downstream margins were weaker in the 2013 quarter compared to a year ago. The corporate function had after-tax costs of $30.3 million in the 2013 second quarter compared to after-tax costs of $15.2 million in the 2012 period with the unfavorable variance in the current period mostly due to higher net interest and administrative expenses.

In the first six months of 2013, the Company s exploration and production operations earned $522.1 million from continuing operations compared to $538.9 million in the same period of 2012. Earnings in 2013 were below the 2012 period primarily due to lower average sales prices for oil and Sarawak natural gas, as well as higher exploration expenses. These variances were partially offset by favorable impact from higher oil sales volumes. The Company s refining and marketing operations had earnings from continuing operations of $97.5 million in the first six months of 2013 compared to earnings of $76.3 million in the same 2012 period. The 2013 period included stronger financial results in the U.S. compared to a year ago based on better ethanol margins and higher values realized on ethanol renewable identification numbers (RINs) credits sold. Corporate after-tax costs were $79.5 million in the 2013 period compared to after-tax costs of $42.5 million in the 2012 period as the current period had higher expenses for interest and administration compared to the prior year.

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

Results of Operations ***(Contd.)***

Exploration and Production

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

	Income (Loss)			
	Three Months Ended June 30,		Six Months Ended June 30,	
(Millions of dollars)	2013	2012	2013	2012
Exploration and production				
United States	$ 122.9	(1.2)	216.7	49.6
Canada	51.7	43.7	65.0	117.0
Malaysia	213.5	223.2	418.7	447.2
Republic of the Congo	(11.7)	(5.3)	(26.5)	(3.7)
Other International	(86.2)	(34.4)	(151.8)	(71.2)
Total	$ 290.2	226.0	522.1	538.9

Second quarter 2013 vs. 2012

United States exploration and production operations reported a profit of $122.9 million in the second quarter of 2013 compared to a loss of $1.2 million in the 2012 quarter. Earnings were improved in the 2013 period due to higher oil production and sales volumes in the Eagle Ford Shale area of South Texas and lower exploration expenses. Lower exploration expense of $55.0 million in 2013 was primarily related to a dry hole in the prior year in the Gulf of Mexico. The 2013 quarter also included lower lease amortization expense as 2012 included costs for expired leases in the dry gas area in the Eagle Ford Shale. Production and depreciation expenses increased $28.1 million and $72.4 million, respectively, in 2013 compared to 2012 mostly due to higher production in the Eagle Ford Shale area. Selling and general expenses in the 2013 period increased $6.4 million from the prior year primarily due to higher staffing costs.

Operations in Canada had earnings of $51.7 million in the second quarter 2013 compared to earnings of $43.7 million in the 2012 quarter. Canadian earnings were higher in the 2013 quarter mostly due to better production volumes for synthetic oil operations in the current year. Oil production increased in Canada in the 2013 period compared to 2012 primarily due to higher heavy oil production in the Seal area of Alberta and at Syncrude, while natural gas sales volumes decreased in 2013 due to lower production in the Tupper area of Western Canada. Production and depreciation expenses for conventional oil operations in Canada were higher in 2013 by $11.9 million and $9.0 million, respectively, due primarily to higher heavy oil production volumes in 2013. Additionally, the 2013 quarter included an impairment charge of $21.6 million to writedown wells performing below expectations in the Kainai area of Southern Alberta.

Operations in Malaysia reported earnings of $213.5 million in the 2013 quarter compared to earnings of $223.2 million during the same period in 2012. Earnings were down in 2013 in Malaysia primarily from a combination of lower sales prices and sales volumes from natural gas fields offshore Sarawak. Production expenses were lower in the 2013 period by $55.2 million primarily due to a favorable adjustment in the 2013 period associated with finalization of gas liquids processing fees retroactive to the beginning of this production and no repeat of well workover costs from the 2012 period. Depreciation expense was $17.3 million more in the 2013 quarter primarily due to higher capital amortization rates in the current quarter.

Operations in Republic of the Congo incurred a loss of $11.7 million in the second quarter of 2013 compared to a loss of $5.3 million in the 2012 quarter. The loss increased in 2013 primarily due to higher expenses in the latest quarter for inventory revaluation, accretion and dry holes.

Other international operations reported a loss of $86.2 million in the second quarter of 2013 compared to a loss of $34.4 million in the 2012 quarter. The higher costs in the current quarter were primarily related to both unsuccessful exploratory drilling costs offshore Australia and higher seismic costs covering prospects in Australia, Vietnam, Indonesia and Suriname.

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

Results of Operations *(Contd.)*

Exploration and Production (Contd.)

Second quarter 2013 vs. 2012 (Contd.)

On a worldwide basis, the Company s crude oil, condensate and gas liquids prices averaged $91.50 per barrel in the second quarter 2013 compared to $94.33 in the 2012 period. Total hydrocarbon production averaged 207,433 barrels of oil equivalent per day in the 2013 second quarter, up from the 188,575 barrel equivalents per day produced in the 2012 quarter. Average crude oil, condensate and gas liquids production was 135,517 barrels per day in the second quarter of 2013 compared to 104,012 barrels per day in the second quarter of 2012, with the increase primarily attributable to higher crude oil production in the Eagle Ford Shale area of South Texas where a significant development drilling and completion program is ongoing. Heavy oil production in the Seal area in Western Canada was higher in 2013 due to volumes produced from lands acquired in the fourth quarter of 2012. Oil production at Syncrude was higher in 2013 due to less downtime for equipment maintenance in the current year. Oil production at the Azurite field, offshore Republic of the Congo, was lower in the 2013 quarter due to well decline. North American natural gas sales prices averaged $3.63 per thousand cubic feet (MCF) in the 2013 quarter compared to $2.15 per MCF in the same quarter of 2012. The average realized price for natural gas produced in 2013 at fields offshore Sarawak was $6.98 per MCF, compared to a price of $7.88 per MCF in the 2012 quarter. Natural gas sales volumes averaged 431 million cubic feet per day in the second quarter 2013, down from 507 million cubic feet per day in the 2012 quarter. The decrease in natural gas sales volumes in 2013 was primarily due to lower gas volumes produced in the Tupper area in Western Canada as development drilling activities have been voluntarily curtailed due to low sales prices for Canadian gas. Additionally, natural gas sales volumes from offshore Sarawak fields in 2013 were less than 2012 due to both performance issues at the third party receiving facility and a lower entitlement allocation to the Company under the production sharing contract.

Six months 2013 vs. 2012

U.S. E&P operations had income of $216.7 million for the six months ended June 30, 2013 compared to income of $49.6 million in the 2012 period. The 2013 period benefited from higher crude oil production volumes at the Eagle Ford Shale area, as well as smaller production increases at fields in the Gulf of Mexico. The 2013 period had higher average realized natural gas sales prices compared to 2012, but realized oil prices were lower year over year. Production and depreciation expenses were $70.0 million and $139.8 million higher, respectively, in 2013 than 2012 mostly due to production growth in the Eagle Ford Shale. Exploration expense in the 2013 period was $49.2 million less than in 2012 primarily due to higher costs in the prior year for an unsuccessful exploration well in the Gulf of Mexico and amortization associated with unproved Eagle Ford Shale leases. Selling and general expenses rose by $10.4 million in 2013 compared to 2012, primarily driven by increased staffing levels.

Canadian operations had income of $65.0 million in the first half of 2013 compared to income of $117.0 million a year ago. Significantly lower sales prices for heavy oil coupled with higher exploration and impairment expenses led to the reduction in 2013 earnings. Natural gas production was significantly lower in 2013, primarily due to lower volumes produced in the Tupper area. Production and depreciation expenses for conventional operations were higher by $10.9 million and $13.3 million, respectively, in 2013 mostly related to higher volumes of heavy oil produced at Seal in the current year. Exploration expenses in 2013 were $21.0 million above 2012 primarily due to dry hole costs at Rainbow in the Muskwa Shale area of Northern Alberta. Impairment expense of $21.6 million in 2013 related to a writedown of wells performing below expectations in the Kainai area of Southern Alberta.

Malaysia operations earned $418.7 million in the first half of 2013 compared to earnings of $447.2 million in the 2012 period. Earnings were down in 2013 primarily due to lower natural gas sales prices and lower natural gas sales volumes offshore Sarawak. The 2013 period benefited from higher sales volumes for Kikeh crude oil production, but average realized sales prices at Kikeh were somewhat lower than in 2012. Production expense in 2013 was lower than in 2012 by $57.8 million primarily due to lower overall costs and a favorable retroactive processing fee adjustment related to gas liquids processing. Depreciation expense was up $38.5 million in the 2013 period primarily due to higher average per-unit depreciation rates for Malaysian production volumes.

Operations in Republic of the Congo had a net loss of $26.5 million for the six-month 2013 period compared to a net loss of $3.7 million in the 2012 period. The unfavorable result in 2013 was primarily due to higher charges for ongoing production operations and costs of $11.3 million for a well workover at the offshore Azurite field in the current year. Due to much lower production during the last year, the 2013 oil sale was attributed a higher number of months of production costs compared to the 2012 sale. The 2013 period included no depreciation expense due to a write-off of all property costs for Azurite at year-end 2012.

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

Results of Operations ***(Contd.)***

Exploration and Production (Contd.)

Six months 2013 vs. 2012 (Contd.)

Other international operations reported a loss of $151.8 million in the first six months of 2013 compared to a loss of $71.2 million in the 2012 period. The 2013 period included higher dry hole costs of $46.5 million, which was primarily associated with unsuccessful wildcat drilling at the Bassett West prospect, offshore Australia. The current period included higher geological and geophysical expense of $34.6 million, principally for various studies and seismic data acquired in several prospective areas, including Australia, Indonesia, Cameroon and other countries. Undeveloped leasehold amortization was $13.0 million lower in the current year, with the reduction mostly attributable to amortization of exploration licenses in the prior year in the Kurdistan region of Iraq.

Total worldwide production averaged 204,653 barrels of oil equivalent per day during the six months ended June 30, 2013, an increase from 191,836 barrels of oil equivalent produced in the same period in 2012. Crude oil, condensate and gas liquids production in the first half of 2013 averaged 131,226 barrels per day compared to 105,751 barrels per day a year ago. The increase was mostly attributable to higher oil production in the Eagle Ford Shale, where additional wells have been brought on production as part of a significant ongoing development drilling and completion program. Oil production in Canada increased in 2013 mostly due to higher levels of heavy oil production in the Seal area of Western Canada. Higher oil production in 2013 in Malaysia was primarily attributable to start-up of the Kakap field in December 2012. Crude oil produced in Republic of the Congo was lower in 2013 than in 2012 due to both field decline and a well going offline in March 2012. For the first six months of 2013, the Company s sales price for crude oil, condensate and gas liquids averaged $93.57 per barrel, down from $97.21 per barrel in 2012. Natural gas sales volumes decreased from 516 million cubic feet per day in 2012 to 440 million cubic feet per day in 2013, with the reduction mostly due to lower gas production volumes in the Tupper area in British Columbia, where drilling activity has been deferred due to generally weak North American natural gas sales prices in 2012 and early 2013. Natural gas sales volumes in 2013 at fields offshore Sarawak were below 2012 levels due to both planned maintenance at the Company s gas receiving facility and a lower entitlement percentage allocation to the Company. The average sales price for North American natural gas in the first six months of 2013 was $3.36 per MCF, up from $2.36 per MCF realized in 2012. Natural gas production at fields offshore Sarawak was sold at an average price of $7.03 per MCF in 2013 compared to $7.80 per MCF in 2012.

Additional details about results of oil and gas operations are presented in the tables on pages 24 and 25.

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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, 2013 and 2012 follow.

	Three Months Ended June 30,		Six Months Ended June 30,	
	2013	2012	2013	2012
Net crude oil, condensate and gas liquids produced barrels per day	135,517	104,012	131,226	105,751
Continuing operations	134,550	100,535	129,920	102,477
United States	48,024	19,746	44,065	20,013
Canada light	162	299	195	252
heavy	10,920	6,874	9,726	7,640
offshore	9,641	8,587	9,443	8,982
synthetic	13,000	11,449	12,710	12,380
Malaysia	51,569	51,523	52,457	50,741
Republic of the Congo	1,234	2,057	1,324	2,469
Discontinued operations United Kingdom	967	3,477	1,306	3,274
Net crude oil, condensate and gas liquids sold barrels per day	137,106	104,768	134,308	106,665
Continuing operations	136,151	101,659	133,055	103,543
United States	48,024	19,746	44,065	20,013
Canada light	162	299	195	252
heavy	10,920	6,874	9,726	7,640
offshore	10,145	10,353	9,050	9,486
synthetic	13,000	11,449	12,710	12,380
Malaysia	53,900	52,938	53,907	50,820
Republic of the Congo			3,402	2,952
Discontinued operations United Kingdom	955	3,109	1,253	3,122
Net natural gas sold thousands of cubic feet per day	431,302	507,379	440,562	516,507
Continuing operations	430,913	504,380	438,919	513,137
United States	51,777	51,867	55,609	51,549
Canada	169,166	242,039	180,420	242,162
Malaysia Sarawak	167,447	181,347	158,316	182,991
Kikeh	42,523	29,127	44,574	36,435
Discontinued operations United Kingdom	389	2,999	1,643	3,370
Total net hydrocarbons produced equivalent barrels per day (1)	207,401	188,575	204,653	191,836
Total net hydrocarbons sold equivalent barrels per day (1)	208,990	189,331	207,735	192,750
Weighted average sales prices				
Crude oil, condensate and gas liquids dollars per barrel (2)				
United States	$ 97.64	102.47	101.67	106.32
Canada (3) light	85.92	78.91	83.64	84.18
heavy	49.90	45.41	39.87	48.44
offshore	102.47	108.30	106.39	112.86
synthetic	98.64	88.97	96.53	93.38
Malaysia (4)	90.50	95.48	92.24	97.47
Republic of the Congo			112.89	107.26
Discontinued operations United Kingdom	101.40	105.79	108.58	112.93
Natural gas dollars per thousand cubic feet				

United States (2)	$ 4.39	2.05	3.90	2.34
Canada (3)	3.40	2.17	3.19	2.36
Malaysia Sarawak (4)	6.98	7.88	7.03	7.80
Kikeh	0.24	0.24	0.24	0.24
Discontinued operations United Kingdom (3)	12.47	9.88	12.32	9.71

(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 terms of the respective production sharing contracts.

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

Results of Operations (Contd.)

OIL AND GAS OPERATING RESULTS THREE MONTHS ENDED JUNE 30, 2013 AND 2012

(Millions of dollars)	United States	Canada Conven-tional	Canada Syn-thetic	Malaysia	Republic of the Congo	Other	Total
Three Months Ended June 30, 2013							
Oil and gas sales and other operating revenues	$ 444.2	200.1	116.7	554.7		(.4)	1,315.3
Production expenses	83.1	52.4	59.0	68.9	8.7		272.1
Depreciation, depletion and amortization	137.7	85.9	14.0	139.7		1.4	378.7
Accretion of asset retirement obligations	3.3	1.5	2.5	3.4	1.3		12.0
Impairment of properties		21.6					21.6
Exploration expenses							
Dry holes		(.1)		.8	1.3	38.3	40.3
Geological and geophysical	.4	(.7)		.8	.1	19.6	20.2
Other	3.1	.3				8.2	11.6
	3.5	(.5)		1.6	1.4	66.1	72.1
Undeveloped lease amortization	7.2	5.3				4.2	16.7
Total exploration expenses	10.7	4.8		1.6	1.4	70.3	88.8
Selling and general expenses	19.5	4.9	.2	.1	.4	14.1	39.2
Results of operations before taxes	189.9	29.0	41.0	341.0	(11.8)	(86.2)	502.9
Income tax provisions (benefits)	67.0	7.6	10.7	127.5	(.1)		212.7
Results of operations (excluding corporate overhead and interest)	$ 122.9	21.4	30.3	213.5	(11.7)	(86.2)	290.2
Three Months Ended June 30, 2012							
Oil and gas sales and other operating revenues	$ 201.7	172.1	92.8	611.3		.1	1,078.0
Production expenses	55.0	40.5	58.7	124.1	3.8		282.1
Depreciation, depletion and amortization	65.3	76.9	12.4	122.4		.5	277.5
Accretion of asset retirement obligations	2.9	1.3	2.2	2.8	.2		9.4
Exploration expenses							
Dry holes	32.2					1.4	33.6
Geological and geophysical	3.3	.1		.2	.1	4.5	8.2
Other	1.8	.3				6.3	8.4
	37.3	.4		.2	.1	12.2	50.2
Undeveloped lease amortization	28.4	7.3				10.8	46.5
Total exploration expenses	65.7	7.7		.2	.1	23.0	96.7
Selling and general expenses	13.1	4.4	.2	(1.4)	1.2	11.0	28.5

Results of operations before taxes	(.3)	41.3	19.3	363.2	(5.3)	(34.4)	383.8
Income tax provisions	.9	12.0	4.9	140.0			157.8
Results of operations (excluding corporate overhead and interest)	$ (1.2)	29.3	14.4	223.2	(5.3)	(34.4)	226.0

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

Results of Operations (Contd.)

OIL AND GAS OPERATING RESULTS SIX MONTHS ENDED JUNE 30, 2013 AND 2012

(Millions of dollars)	United States	Canada Conven-tional	Canada Syn-thetic	Malaysia	Republic of the Congo	Other	Total
Six Months Ended June 30, 2013							
Oil and gas sales and other operating revenues	$ 853.1	355.5	222.1	1,114.7	69.5	(.6)	2,614.3
Production expenses	173.5	95.8	115.0	155.5	84.6		624.4
Depreciation, depletion and amortization	268.1	167.4	27.7	273.6		2.6	739.4
Accretion of asset retirement obligations	6.6	3.0	5.2	6.7	2.4		23.9
Impairment of properties		21.6					21.6
Exploration expenses							
Dry holes	.7	30.4		1.2	1.3	47.7	81.3
Geological and geophysical	13.1	(.6)		1.1	.1	46.0	59.7
Other	4.6	.6			.1	18.9	24.2
	18.4	30.4		2.3	1.5	112.6	165.2
Undeveloped lease amortization	13.3	10.6				8.2	32.1
Total exploration expenses	31.7	41.0		2.3	1.5	120.8	197.3
Selling and general expenses	35.6	11.3	.4	.6	.9	27.8	76.6
Results of operations before taxes	337.6	15.4	73.8	676.0	(19.9)	(151.8)	931.1
Income tax provisions	120.9	4.8	19.4	257.3	6.6		409.0
Results of operations (excluding corporate overhead and interest)	$ 216.7	10.6	54.4	418.7	(26.5)	(151.8)	522.1
Six Months Ended June 30, 2012							
Oil and gas sales and other operating revenues	$ 422.8	361.5	210.4	1,175.3	57.6	.1	2,227.7
Production expenses	103.5	84.9	111.3	213.3	20.8		533.8
Depreciation, depletion and amortization	128.3	154.1	25.7	235.1	33.8	1.1	578.1
Accretion of asset retirement obligations	5.7	2.6	4.2	5.7	.4		18.6
Exploration expenses							
Dry holes	32.2	.8				1.2	34.2
Geological and geophysical	3.5	4.3		.2	.2	11.4	19.6
Other	5.7	.5			.2	14.4	20.8
	41.4	5.6		.2	.4	27.0	74.6
Undeveloped lease amortization	39.5	14.4				21.2	75.1
Total exploration expenses	80.9	20.0		.2	.4	48.2	149.7
Selling and general expenses	25.2	8.5	.4	(1.1)	2.1	22.0	57.1

Results of operations before taxes	79.2	91.4	68.8	722.1	.1	(71.2)	890.4
Income tax provisions	29.6	25.8	17.4	274.9	3.8		351.5
Results of operations (excluding corporate overhead and interest)	$ 49.6	65.6	51.4	447.2	(3.7)	(71.2)	538.9

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

Results of Operations (Contd.)

Refining and Marketing

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

	Income (Loss)			
	Three Months Ended June 30,		Six Months Ended June 30,	
(Millions of dollars)	2013	2012	2013	2012
Refining and marketing				
United States	$ 77.9	73.3	107.3	66.1
United Kingdom	(5.7)	7.2	(9.8)	10.2
Total	$ 72.2	80.5	97.5	76.3

Second Quarter 2013 vs. 2012

The Company has announced its intention to separate its U.S. retail marketing business into a separate publicly owned company. The Company has also announced its intention to sell its U.K. refining and marketing operations. The separation process for the U.S. retail marketing business and the sale process for the U.K. downstream operations continue to progress.

The United States refining and marketing segment includes retail and wholesale fuel marketing operations and two ethanol production facilities. The United Kingdom refining and marketing segment includes the Milford Haven, Wales refinery and U.K. retail and other refined products marketing operations.

United States operations generated a profit of $77.9 million in the 2013 second quarter compared to a profit of $73.3 million during the second quarter of 2012. The favorable result in the 2013 quarter was primarily due to stronger results for the Company s two ethanol production facilities during the current period, coupled with higher values realized for ethanol RINs credits sold in the current year. RINs were sold at an average of $0.78 per credit in 2013 compared to $0.02 per credit in 2012. U.S. retail marketing margins were slightly weaker in 2013 compared to the 2012 quarter. U.S. retail margins averaged $0.156 per gallon in 2013 and $0.197 per gallon in 2012. Overall per-store retail fuel sales volumes in the current period were above 2012 levels by 1.2%. U.S. retail operations generated lower profits from merchandise sales in the 2013 quarter due to a reduction in per-store sales by almost 1% and a lower margin generated as a percentage of sales. The latter was mostly driven by lower margins realized on certain tobacco products in the 2013 quarter. The ethanol production business had more favorable operating results in 2013 than in 2012 as margins at the Hankinson, North Dakota and Hereford, Texas plants were well above prior year levels, leading to profitable results for both plants in 2013 following losses in 2012. Compared to the 2012 second quarter, ethanol sales prices rose more than corn feedstock costs during 2013.

Refining and marketing operations in the United Kingdom incurred a loss of $5.7 million in the second quarter of 2013 compared to a profit of $7.2 million in the same quarter of 2012. The U.K. results in 2013 were unfavorably affected by weaker refining margins during the just completed quarter. Margins for the U.K. marketing business were stronger in 2013, somewhat offsetting the effect of lower refining margins. Unit margins averaged $(0.27) per barrel in the U.K. in the 2013 quarter, well below the $1.26 per barrel margin achieved in 2012. Crude oil throughput volumes at the Milford Haven refinery were 130,324 barrels per day during the 2013 quarter, compared to throughputs of 130,059 barrels per day in the 2012 second quarter.

Worldwide petroleum product sales were 481,727 barrels per day in the 2013 quarter, down from 483,561 barrels per day a year ago. This decrease was mostly due to lower product sales volumes in the Company s U.K. operations in the current year.

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

Results of Operations (Contd.)

Refining and Marketing (Contd.)

Six months 2013 vs. 2012

United States operations generated a profit of $107.3 million in the first six months of 2013 compared to a profit of $66.1 million during the 2012 period. Results in 2013 were above 2012 levels primarily due to stronger U.S. ethanol margins and higher sales values for RINs during the current year. U.S. retail marketing margins averaged $0.134 per gallon in 2013 following a margin of $0.137 per gallon in 2012. Per-store fuel sales volumes for the retail operations in the 2013 period were about flat with 2012 levels. These U.S. retail operations generated less profits from merchandise sales in 2013 due to lower sales per store of 2.4% and a lower margin as a percentage of sales of 2.2% during the current year. Ethanol production operations generated profits in the first six months of 2013, compared to losses in the 2012 period. Operating margins for the ethanol facilities were improved in the 2013 period as the sales prices for ethanol rose more than the price of corn feedstock.

Refining and marketing operations in the United Kingdom incurred a loss of $9.8 million in the 2013 six months compared to income of $10.2 million in the same 2012 period. The U.K. business in 2013 experienced lower refining margins, which were only partially offset by improved marketing margins. Overall U.K. unit margins averaged $(0.16) per barrel in 2013 compared to $1.03 per barrel in 2012. Crude oil throughput volumes at Milford Haven were 121,417 barrels per day in 2013, down from 128,530 barrels per day in 2012.

Total petroleum product sales were 453,058 barrels per day in the 2013 period, down from 467,049 barrels per day a year ago, with the volume decrease due to both lower third party sales volumes through the U.S. terminal network and lower U.K. operations sales volumes in the current year.

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

Results of Operations (Contd.)

Refining and Marketing (Contd.)

Selected operating statistics for the three-month and six-month periods ended June 30, 2013 and 2012 follow.

	Three Months Ended June 30,		Six Months Ended June 30,	
	2013	2012	2013	2012
United States retail marketing:				
Fuel margin per gallon*	$ 0.156	0.197	$ 0.134	$ 0.137
Gallons sold per store month	278,977	275,741	264,994	265,302
Merchandise sales revenue per store month	$ 157,138	158,626	152,072	$ 155,783
Merchandise margin as a percentage of merchandise sales	12.8%	13.4%	12.9%	13.2%
Store count at end of period (Company operated)	1,179	1,139	1,179	1,139
United Kingdom refining and marketing unit margins per barrel	$ (0.27)	$ 1.26	$ (0.16)	$ 1.03
Petroleum products sold barrels per day	481,727	483,561	453,058	467,049
United States	344,210	344,415	325,108	332,195
Gasoline	296,900	294,282	280,921	284,336
Kerosine	8	16	100	116
Diesel and home heating oils	47,302	50,117	44,087	47,743
United Kingdom	137,517	139,146	127,950	134,854
Gasoline	49,103	46,981	46,819	45,830
Kerosine	15,370	19,584	15,238	17,728
Diesel and home heating oils	51,103	49,249	46,592	46,466
Residuals	16,869	16,676	14,795	16,187
LPG and other	5,072	6,656	4,506	8,643
U.K. refinery inputs barrels per day	133,220	133,158	124,542	131,954
Milford Haven, Wales crude oil	130,324	130,059	121,417	128,530
other feedstocks	2,896	3,099	3,125	3,424
U.K. refinery yields barrels per day	133,220	133,158	124,542	131,954
Gasoline	47,292	44,961	43,875	44,767
Kerosine	17,058	17,985	16,266	17,037
Diesel and home heating oils	48,626	48,762	44,637	44,551
Residuals	15,309	15,874	13,731	15,730
LPG and other	1,757	2,033	2,952	6,313
Fuel and loss	3,178	3,543	3,081	3,556

* Represents net sales prices for fuel less purchased cost of fuel.

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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 $30.3 million in the 2013 second quarter compared to net costs of $15.2 million in the second quarter of 2012. The current year costs were unfavorable compared to the prior year due to higher expenses for interest and administration. The increase in net interest expense was mostly associated with a higher level of borrowings in the current year, but this was partially offset by additional financing costs being allocated to ongoing oil development projects in 2013. Higher administrative expenses were associated with employee compensation and consulting fees related to the upcoming separation of the U.S. downstream business into a stand-alone, public company. Partially offsetting these higher costs, net after-tax gains of $16.2 million in 2013 on transactions denominated in foreign currencies compared favorably to net after-tax gains of $10.7 million in the comparable 2012 period.

For the first six months of 2013, corporate activities reflected net costs of $79.5 million compared to net costs of $42.5 million a year ago. Six-month corporate costs in 2013 were unfavorable to 2012 mostly related to higher expenses for interest and corporate administration. Net interest expense was higher in 2013 compared to 2012 primarily due to larger average borrowings in the current year. Administrative expense was higher in 2013 associated with increased employee compensation costs and consulting costs associated with the upcoming separation of the U.S. downstream business. Total after-tax gains for foreign currency transactions were $12.2 million in the 2013 period compared to after-tax gains of $9.1 million in the first six months of 2012.

Discontinued Operations

The Company sold its U.K. oil and gas properties in the first six months of 2013. See Note D of the consolidated financial statements for further information. The Company has accounted for the results of the U.K. oil and gas business as discontinued operations in all periods presented. Income from discontinued operations was $70.5 million in the 2013 second quarter compared to income of $4.1 million in the 2012 quarter. The 2013 increase primarily included a $71.9 million after-tax gain on disposal of the Mungo and Monan fields.

During the six-month period ended June 30, 2013, income from discontinued operations totaled $223.1 million, including total after-tax gains of $216.2 million on sale of all U.K. oil and gas assets. The 2012 six months included income from discontinued operations of $12.8 million.

Financial Condition

Net cash provided by operating activities was $1,669.0 million for the first six months of 2013 compared to $1,347.1 million during the same period in 2012. Changes in operating working capital other than cash and cash equivalents from continuing operations generated cash of $65.1 million during the first six months of 2013, but these working capital changes required cash of $103.3 million in 2012. Cash of $358.9 million in the 2013 period and $897.8 million in 2012 was generated from maturity of Canadian government securities that had maturity dates greater than 90 days at acquisition. The sale of all U.K. oil and gas properties generated cash proceeds of $282.2 million during 2013.

Significant uses of cash in both years were for dividends, which totaled $119.4 million in 2013 and $106.8 million in 2012, and for property additions and dry holes for continuing operations, which including amounts expensed, were $1,963.6 million and $1,314.6 million in the six-month periods ended June 30, 2013 and 2012, respectively. The Company paid quarterly per-share dividends on outstanding common shares of $0.3125 in the first two quarters of 2013 and $0.275 in the same 2012 periods. The Company acquired 4,176,828 shares of common stock through share repurchases during the first six months of 2013. The total cash expended on these share repurchases totaled $250.0 million during 2013. Also, the purchase of Canadian government securities with maturity dates greater than 90 days at acquisition used cash of $373.2 million in the 2013 period and $836.5 million in the 2012 period.

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

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

Total accrual basis capital expenditures for continuing operations were as follows:

(Millions of dollars)	Six Months Ended June 30, 2013	2012
Capital Expenditures		
Exploration and production	$ 1,960.5	1,568.3
Refining and marketing	105.2	55.4
Corporate	6.6	3.4
Total capital expenditures	$ 2,072.3	1,627.1

The increase in capital expenditures in the exploration and production business in 2013 was primarily attributable to more drilling and development activities in the Eagle Ford Shale area. Capital expenditures exclude production equipment leased at the Kakap field, offshore Malaysia, during 2013. The increase in refining and marketing capital expenditures in 2013 primarily related to higher spend on land acquired for future stations to be built adjacent to Walmart stores in the U.S.

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

(Millions of dollars)	Six Months Ended June 30, 2013	2012
Property additions and dry hole costs per cash flow statements	$ 1,963.6	1,314.6
Geophysical and other exploration expenses	83.9	40.4
Capital expenditure accrual changes	24.8	272.1
Total capital expenditures	$ 2,072.3	1,627.1

Working capital (total current assets less total current liabilities) at June 30, 2013 was $663.4 million, a decrease of $36.1 million from December 31, 2012. 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 $553.4 million below fair value at June 30, 2013.

At June 30, 2013, long-term debt of $3,046.1 million had increased by $800.9 million compared to December 31, 2012. The increase during 2013 included $338.6 million associated with a capital lease of production equipment at the Kakap field, offshore Malaysia. Excluding this capital lease, long-term debt would equal 22.9% of capital employed. A summary of capital employed at June 30, 2013 and December 31, 2012 follows.

(Millions of dollars)	June 30, 2013 Amount	%	Dec. 31, 2012 Amount	%

Capital employed				
Long-term debt	$ 3,046.1	25.0%	$ 2,245.2	20.1%
Stockholders equity	9,134.2	75.0	8,942.0	79.9
Total capital employed	$ 12,180.3	100.0%	$ 11,187.2	100.0%

The Company s ratio of earnings to fixed charges was 12.6 to 1 for the six-month period ended June 30, 2013.

Cash and invested cash are maintained in several operating locations outside the United States. At June 30, 2013, cash, cash equivalents and cash temporarily invested in Canadian government securities held outside the U.S. included U.S. dollar equivalents of approximately $230 million in Canada, $517 million in Malaysia and $240 million in the United Kingdom. In certain cases, the Company could incur taxes or other costs should these cash balances be repatriated to the U.S. in future periods. This could occur due to withholding taxes and/or potential additional U.S. tax burden when less than the U.S. Federal tax rate of 35% has been paid for cash taxes in foreign locations. A lower cash tax rate is often paid in foreign countries in the early years of operations when accelerated tax deductions exist to spur oil and gas investments; cash tax rates are generally higher in later years after accelerated tax deductions in early years are exhausted. Canada collects a 5% withholding tax on any cash repatriated to the United States.

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

Accounting and Other Matters

In December 2011, the Financial Accounting Standards Board (FASB) issued an accounting standards update that requires enhanced disclosures about financial instruments and derivative instruments that are either offset in the balance sheet or are subject to an enforceable master netting arrangement or similar agreement. The guidance was effective for all interim and annual periods beginning on or after January 1, 2013. These disclosures are presented in Note K to the consolidated financial statements.

In February 2013, the FASB issued an accounting standards update that requires additional disclosures for reclassification adjustments from accumulated other comprehensive income (AOCI). These additional disclosures include changes in AOCI balances by component and significant items reclassified out of AOCI. These disclosures must be presented either on the face of the affected financial statement or in the notes to the financial statements. The disclosures are effective for Murphy Oil beginning in the first quarter of 2013 and are to be provided on a prospective basis. These disclosures are presented in Note L to the consolidated financial statements.

The United States Congress passed the Dodd-Frank Act (the Act) in 2010. As mandated by the Act, the U.S. Securities and Exchange Commission (SEC) issued rules regarding annual disclosures for purchases of conflict minerals and payments made to the U.S. Federal and all foreign governments by extractive industries, including oil and gas companies. Conflict minerals are defined as tin, tantalum, tungsten and gold which originate from the Democratic Republic of Congo or adjoining countries. The Company is currently investigating whether its activities will require an annual conflict minerals filing. If applicable, the first annual report for conflict minerals must be filed by May 31, 2014 for the calendar year of 2013.

On July 2, 2013, the United States District Court for the District of Columbia vacated the SEC s rules regarding reporting of payments made to the U.S. Federal and foreign governments. The decision was based on a ruling that (1) the SEC rules mandated public disclosure of the resource extraction payments when the Act did not require this, and (2) the SEC s denial of an exemption for reporting of payments under contracts where such reporting is prohibited by host country law. The Court remanded the rulemaking to the SEC for further proceedings. The Company cannot predict how the SEC will alter its rules based on the Court s findings.

Outlook

Average crude oil prices in July 2013 have strengthened compared to the average price during the second quarter of 2013. Oil prices have purportedly risen due to market concern over unrest in Egypt and Syria. The Company expects its oil and natural gas production to average about 190,000 barrels of oil equivalent per day in the third quarter 2013. The projected production decline in the third quarter is primarily due to anticipated downtime at Kikeh for tie-in of the Siakap field. The Company anticipates total hydrocarbon productions levels of 203,000 barrels of oil equivalent per day for the full year of 2013. Margins for both U.S. retail marketing and ethanol operations margins have weakened in July versus the averages achieved in the second quarter 2013. The Company currently anticipates total capital expenditures for the full year 2013 to be approximately $4.3 billion.

The Company will primarily fund its capital program in 2013 using operating cash flow, but will supplement funding where necessary using borrowings under available credit facilities. The Company s 2013 budget calls for borrowings of long-term debt during the year to fund a portion of the capital program. If oil and/or natural gas prices weaken, actual cash flow generated from operations could be reduced such that higher than anticipated borrowings might be required during the year to maintain funding of the Company s ongoing development projects. Additionally, the 2013 budget assumes further share repurchases under the previously announced share buyback program of up to $1.0 billion. Through June 30, 2013, the Company had repurchased 8,044,378 shares at a cost of $500 million under the repurchase program. The level of any additional share repurchases could also influence the amount of long-term debt outstanding under credit facilities during 2013.

The Company has announced that it plans to exit the U.K. refining and marketing business. The sale process for this U.K. business continues to progress in 2013. Should the Company be unable to sell its U.K. refining and marketing assets on acceptable terms, this could require additional borrowings under credit facilities during 2013.

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

Outlook (Contd.)

In 2012, the Company announced its intention to separate its U.S. retail marketing business into a stand-alone publicly owned company. This separation is expected to be completed in 2013. The Company expects that the stand-alone U.S. retail marketing business will have outstanding debt and will provide Murphy Oil Corporation with a cash dividend upon separation. The level of this cash dividend also could influence the amount of long-term debt outstanding for Murphy Oil during 2013.

After the anticipated separation of the U.S. retail marketing business from Murphy Oil Corporation during 2013, and the desired sale of the U.K. downstream business, the Company will have significantly lower sales revenue as the U.S. and U.K. businesses generated about 81% of Murphy s consolidated revenue. These businesses also produced about 16% of income from continuing operations before considering unallocated corporate net costs during the first six months of 2013, and they employed about 79% of the Company s workforce at June 30, 2013. The Company also anticipates that without these operations, it is no longer expected to qualify as a member of the Fortune 500 group of companies. Murphy Oil is anticipated to be an independent oil and gas company in the future and will not have a significant refining and marketing business as a diversification to its oil and gas business. This decrease in size and change in diversification could impact its credit rating, and could, although not expected to, impact its ability to repay long-term debt obligations when due. The future separation of the U.S. retail marketing business and the future sale of the U.K. downstream will lead to reclassifications of these results as discontinued operations in the Company s consolidated financial statements in a future period.

As noted above, crude oil sales prices have strengthened in July 2013. Should future oil prices weaken significantly below the average prices in the second quarter 2013, it is possible that certain investments in oil properties could become impaired in a future period.

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, adverse foreign exchange movements, political and regulatory instability, and uncontrollable natural hazards. Factors that could cause the forecasted separation of its U.S. retail marketing business, as discussed in this Form 10-Q, not to occur include, but are not limited to, a failure to obtain necessary regulatory approvals, a failure to obtain assurances of anticipated tax treatment, a deterioration in the business or prospects of Murphy or its U.S. retail marketing business, adverse developments in Murphy or its U.S. retail marketing business markets, and adverse developments in the U.S. or global capital markets, credit markets or economies in general. Additionally, the Company may be unable to sell its U.K. downstream business as it desires to do because it may fail to execute a sale of these operations on acceptable terms. For further discussion of risk factors, see Murphy s 2012 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.

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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 K 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, 2013 to hedge the purchase price of corn and the sale price of wet and dried distillers grain at the Company s ethanol production facilities. A 10% increase in the respective benchmark price of these commodities would have reduced the recorded net asset associated with these derivative contracts by approximately $0.1 million, while a 10% decrease would have increased the recorded net 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, 2013 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 increased the recorded net liability associated with these contracts by approximately $18.1 million, while a 10% weakening of the U.S. dollar would have reduced the recorded net liability by approximately $21.5 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, 2013 that have materially affected, or are reasonably likely to materially affect, the Company s internal control over financial reporting.

PART II OTHER INFORMATION

ITEM 1. LEGAL PROCEEDINGS

In March 2013, a subsidiary of the Company paid a fine amounting to $151,250 to the U.S. Department of Transportation for violations of the pipeline and hazardous Materials Safety Administration (PHMSA), Office of Pipeline Safety (OPS) of 49 C.F.R.R. Part 195 from an on-site pipeline safety inspection of its former Superior, Wisconsin refinery. The subsidiary had recorded an expense related to this fine in a prior year.

Murphy is engaged in a number of 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 2012 Form 10-K filed on February 28, 2013. The Company has not identified any additional risk factors not previously disclosed in its 2012 Form 10-K report.

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

Murphy Oil Corporation

Issuer Purchases of Equity Securities

Period	Total Number of Shares Purchased*	Average Price Paid per Share	Total Number of Shares Purchased as Part of Publicly Announced Plans or Programs	Approximate Dollar Value of Shares that May Yet Be Purchased Under the Plans or Programs*
April 1, 2013 to April 30, 2013		$		$ 750,000,000
May 1, 2013 to May 31, 2013	3,896,449	64.16	3,896,449	500,000,000
June 1, 2013 to June 30, 2013	280,379	0.00	280,379	500,000,000
Total April 1, 2013 to June 30, 2013	**4,176,828**	**59.85**	**4,176,828**	**500,000,000**

* On October 16, 2012, the Company announced that its Board of Directors had authorized a buyback of up to $1.0 billion of the Company s Common stock. To date, Murphy has completed two variable term, capped accelerated share repurchase transactions (ASR) with major financial institutions at a total cash outlay of $500 million. The total aggregate number of shares repurchased pursuant to these ASR was determined by reference to the Rule 10b-18 volume-weighted price of the Company s Common stock, less a fixed discount, over the term of the respective ASR, subject to a minimum number of shares. The results of the ASR are summarized as follows:

Start Date	Completion Date	Total Cost	Total Shares Repurchased	Final Average Share Cost
December 10, 2012	May 23, 2013	$ 250,000,000	4,064,261	$ 61.51
May 23, 2013	June 25, 2013	250,000,000	3,980,117	62.81
		$ 500,000,000	8,044,378	$ 62.16

ITEM 6. EXHIBITS

The Exhibit Index on page 36 of this Form 10-Q report lists the exhibits that are hereby filed or incorporated by reference.

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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, Senior Vice President and Controller *(Chief Accounting Officer and Duly Authorized Officer)*

August 6, 2013

(Date)

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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

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