MURPHY OIL CORP /DE
Form 10-Q
November 05, 2014

UNITED STATES SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

FORM 10-Q

(Mark one)

[X] QUARTERLY REPORT PURSUANT TO SECTION 13 OR 15(d)

OF THE SECURITIES EXCHANGE ACT OF 1934

For the quarterly period ended September 30, 2014

OR

[ ] TRANSITION REPORT PURSUANT TO SECTION 13 OR

15(d) OF THE SECURITIES EXCHANGE ACT OF 1934

For the transition period from _______________ to _______________

Commission File Number 1-8590

MURPHY OIL CORPORATION

(Exact name of registrant as specified in its charter)

Delaware (State or other jurisdiction of incorporation or organization)	71-0361522 (I.R.S. Employer Identification No.)
200 Peach Street P.O. Box 7000, El Dorado, Arkansas (Address of principal executive offices)	71731-7000 (Zip Code)

(870) 862-6411

(Registrant's telephone number, including area code)

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days.

Yes No

Indicate by check mark whether the registrant 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).

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 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 No

Number of shares of Common Stock, $1.00 par value, outstanding at September 30, 2014 was 177,494,772.

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) September 30, 2014	December 31, 2013
ASSETS		
Current assets		
Cash and cash equivalents	$ 674,021	750,155
Canadian government securities with maturities greater than 90 days at the date of acquisition	460,190	374,842
Accounts receivable, less allowance for doubtful accounts of $1,609 in 2014 and 2013	970,286	999,872
Inventories, at lower of cost or market		
Crude oil	40,311	40,077
Materials and supplies	259,644	254,118
Prepaid expenses	86,091	83,856
Deferred income taxes	60,700	61,991
Assets held for sale	735,875	943,732
Total current assets	3,287,118	3,508,643
Property, plant and equipment, at cost less accumulated depreciation, depletion and amortization of $9,698,266 in 2014 and $8,540,239 in 2013	14,372,837	13,481,055
Goodwill	38,198	40,259
Deferred charges and other assets	87,106	98,123
Assets held for sale	60,507	381,404
Total assets	$ 17,845,766	17,509,484
LIABILITIES AND STOCKHOLDERS' EQUITY		
Current liabilities		
Current maturities of long-term debt	$ 39,607	26,249
Accounts payable and accrued liabilities	2,249,579	2,335,712
Income taxes payable	145,185	222,930
Liabilities associated with assets held for sale	185,846	639,140
Total current liabilities	2,620,217	3,224,031

Long-term debt, including capital lease obligation	3,986,261	2,936,563
Deferred income taxes	1,519,677	1,466,100
Asset retirement obligations	897,765	852,488
Deferred credits and other liabilities	344,301	339,028
Liabilities associated with assets held for sale	75,037	95,544
Stockholders' equity		
Cumulative Preferred Stock, par $100, authorized 400,000 shares, none issued	–	–
Common Stock, par $1.00, authorized 450,000,000 shares, issued 195,036,689 shares in 2014 and 194,920,155 shares in 2013	195,037	194,920
Capital in excess of par value	896,567	902,633
Retained earnings	8,414,917	8,058,792
Accumulated other comprehensive income (loss)	(17,809)	172,119
Treasury stock, 17,541,917 shares of Common Stock in 2014 and 11,513,642 shares of Common Stock in 2013, at cost	(1,086,204)	(732,734)
Total stockholders' equity	8,402,508	8,595,730
Total liabilities and stockholders' equity	$ 17,845,766	17,509,484

See Notes to Consolidated Financial Statements, page 7.

The Exhibit Index is on page 38.

Murphy Oil Corporation and Consolidated Subsidiaries

CONSOLIDATED STATEMENTS OF INCOME (unaudited)

(Thousands of dollars, except per share amounts)

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2014	2013*	2014	2013*
REVENUES				
Sales and other operating revenues	$ 1,431,007	1,366,434	4,070,120	3,980,960
Loss on sale of assets	(133)	(38)	(5,130)	(262)
Interest and other income	2,163	53,100	3,468	61,722
Total revenues	1,433,037	1,419,496	4,068,458	4,042,420
COSTS AND EXPENSES				
Lease operating expenses	265,518	258,524	813,638	847,522
Severance and ad valorem taxes	28,574	22,393	83,793	57,790
Exploration expenses, including undeveloped lease amortization	117,433	147,845	390,711	345,110
Selling and general expenses	82,960	99,333	269,986	267,704
Depreciation, depletion and amortization	499,151	394,667	1,354,393	1,139,193
Impairment of assets	–	–	–	21,587
Accretion of asset retirement obligations	12,600	12,539	36,992	36,396
Interest expense	34,970	33,535	101,625	90,156
Interest capitalized	(5,323)	(13,011)	(19,244)	(40,877)
Other expense	662	–	1,297	–
Total costs and expenses	1,036,545	955,825	3,033,191	2,764,581
Income from continuing operations before income taxes	396,492	463,671	1,035,267	1,277,839
Income tax expense	125,435	198,593	452,255	570,189
Income from continuing operations	271,057	265,078	583,012	707,650
Income (loss) from discontinued operations, net of taxes	(25,350)	19,731	(52,639)	340,402
NET INCOME	$ 245,707	284,809	530,373	1,048,052
PER COMMON SHARE – BASIC				
Income from continuing operations	$ 1.52	1.42	3.25	3.75
Income (loss) from discontinued operations	(0.14)	0.10	(0.29)	1.80
Net income	$ 1.38	1.52	2.96	5.55
PER COMMON SHARE – DILUTED				
Income from continuing operations	$ 1.51	1.41	3.23	3.72
Income (loss) from discontinued operations	(0.14)	0.10	(0.29)	1.79

Net income	$ 1.37	1.51	2.94	5.51
Average Common shares outstanding				
Basic	177,535,503	186,938,328	179,259,573	188,914,000
Diluted	178,856,078	188,337,511	180,578,085	190,245,166

*Reclassified to conform to current presentation - See Note D.

See Notes to Consolidated Financial Statements, page 7.

Murphy Oil Corporation and Consolidated Subsidiaries

CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME (unaudited)

(Thousands of dollars)

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2014	2013	2014	2013
Net income	$ 245,707	284,809	530,373	1,048,052
Other comprehensive income (loss), net of tax				
Net gain (loss) from foreign currency translation	(192,329)	95,065	(195,374)	(139,943)
Retirement and postretirement benefit plans	1,505	1,279	3,996	8,549
Deferred loss on interest rate hedges reclassified to interest expense	484	483	1,450	1,453
Other comprehensive income (loss)	(190,340)	96,827	(189,928)	(129,941)
COMPREHENSIVE INCOME	$ 55,367	381,636	340,445	918,111

See Notes to Consolidated Financial Statements, page 7.

Murphy Oil Corporation and Consolidated Subsidiaries

CONSOLIDATED STATEMENTS OF CASH FLOWS (unaudited)

(Thousands of dollars)

	Nine Months Ended September 30,	
	2014	20131
OPERATING ACTIVITIES		
Net income	$ 530,373	1,048,052
Adjustments to reconcile net income to net cash provided by operating activities:		
Loss (income) from discontinued operations	52,639	(340,402)
Depreciation, depletion and amortization	1,354,393	1,139,193
Impairment of assets	–	21,587
Amortization of deferred major repair costs	6,390	6,387
Dry hole costs	203,607	160,540
Amortization of undeveloped leases	55,745	53,287
Accretion of asset retirement obligations	36,992	36,396
Deferred and noncurrent income tax charges	64,557	141,402
Pretax loss from disposition of assets	5,130	262
Net (increase) decrease in noncash operating working capital	6,940	(24,545)
Other operating activities, net	17,531	(24,206)
Net cash provided by continuing operations	2,334,297	2,217,953
Net cash provided by discontinued operations	19,720	460,563
Net cash provided by operating activities	2,354,017	2,678,516
INVESTING ACTIVITIES		
Property additions and dry hole costs2	(2,806,705)	(2,695,507)
Proceeds from sales of assets	3,138	1,371
Purchase of investment securities3	(672,689)	(670,615)
Proceeds from maturity of investment securities3	587,341	496,425
Investing activities of discontinued operations:		
Sales proceeds	–	282,202
Property additions and other	(12,101)	(158,363)
Other – net	(19,233)	(1,383)
Net cash required by investing activities	(2,920,249)	(2,745,870)
FINANCING ACTIVITIES		
Borrowings of long-term debt2	1,050,000	–
Purchase of treasury stock	(375,000)	(250,000)
Proceeds from exercise of stock options and employee stock purchase plans	–	2,778
Witholding tax on stock-based incentive awards	(6,786)	(12,713)
Cash dividends paid	(174,248)	(177,805)

Separation of retail business:		
Cash distributed to Company by Murphy USA	–	650,000
Cash held and retained by Murphy USA upon separation	–	(55,506)
Other – net	(1,384)	(3,034)
Net cash provided by financing activities	492,582	153,720
Effect of exchange rate changes on cash and cash equivalents	(2,484)	255
Net increase (decrease) in cash and cash equivalents	(76,134)	86,621
Cash and cash equivalents at January 1	750,155	947,316
Cash and cash equivalents at September 30	$ 674,021	1,033,937

1Reclassified to conform to current presentation – See Note D.

2 Excludes non-cash asset and long-term obligation of $356,170 in 2013 associated with commencement of a capital lease of

production equipment at the Kakap field offshore Malaysia.

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

See Notes to Consolidated Financial Statements, page 7.

Murphy Oil Corporation and Consolidated Subsidiaries

CONSOLIDATED STATEMENTS OF STOCKHOLDERS' EQUITY (unaudited)

(Thousands of dollars)

	Nine Months Ended September 30, 2014	2013
Cumulative Preferred Stock – par $100, authorized 400,000 shares, none issued	$ –	–
Common Stock – par $1.00, authorized 450,000,000 shares, issued 195,036,689 shares at September 30, 2014 and 194,861,200 shares at September 30, 2013		
Balance at beginning of period	194,920	194,616
Exercise of stock options	117	245
Balance at end of period	195,037	194,861
Capital in Excess of Par Value		
Balance at beginning of period	902,633	873,934
Exercise of stock options, including income tax benefits	(11,354)	1,194
Restricted stock transactions and other	(27,977)	(24,485)
Stock-based compensation	33,291	44,079
Other	(26)	(122)
Balance at end of period	896,567	894,600
Retained Earnings		
Balance at beginning of period	8,058,792	7,717,389
Net income for the period	530,373	1,048,052
Cash dividends	(174,248)	(177,805)
Distribution of common stock of Murphy USA Inc. to shareholders	–	(552,587)
Balance at end of period	8,414,917	8,035,049
Accumulated Other Comprehensive Income		
Balance at beginning of period	172,119	408,901
Foreign currency translation loss, net of income taxes	(195,374)	(139,943)
Retirement and postretirement benefit plans, net of income taxes	3,996	8,549
Deferred loss on interest rate hedges reclassified to interest expense, net of income taxes	1,450	1,453
Balance at end of period	(17,809)	278,960
Treasury Stock		

Balance at beginning of period	(732,734)	(252,805)
Purchase of treasury shares	(375,000)	(250,000)
Sale of stock under employee stock purchase plans	345	836
Awarded restricted stock, net of forfeitures	21,185	16,545
Balance at end of period	(1,086,204)	(485,424)
Total Stockholders' Equity	$ 8,402,508	8,918,046

See notes to Consolidated Financial Statements, page 7.

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, 2013. In the opinion of Murphy's management, the unaudited financial statements presented herein include all accruals necessary to present fairly the Company's financial position at September 30, 2014, and the results of operations, cash flows and changes in stockholders' equity for the three-month and nine-month periods ended September 30, 2014 and 2013, in conformity with accounting principles generally accepted in the United States of America (U.S.). In preparing the financial statements of the Company in conformity with accounting principles generally accepted in the U.S., 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 2013 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 nine-month periods ended September 30, 2014 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 September 30, 2014, the Company had total capitalized exploratory well costs pending the determination of proved reserves of $406.6 million. The following table reflects the net changes in capitalized exploratory well costs during the nine-month periods ended September 30, 2014 and 2013.

(Thousands of dollars)	2014	2013
Beginning balance at January 1	$ 393,030	445,697
Additions pending the determination of proved reserves	13,595	28,168
Reclassifications to proved properties based on the determination of proved reserves	–	(52,865)
Balance at September 30	$ 406,625	421,000

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.

	September 30, 2014			2013		
(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	$ 32,192	2	1	$ 36,424	2	2
One to two years	36,676	2	1	51,444	6	–
Two to three years	51,898	6	–	35,504	3	3
Three years or more	285,859	22	7	297,628	27	5
	$ 406,625	32	9	$ 421,000	38	10

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Contd.)

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

Of the $374.4 million of exploratory well costs capitalized more than one year at September 30, 2014, $214.8 million is in Malaysia, $125.9 million is in the U.S. and $33.7 million is in Brunei. In all three geographical areas, either further appraisal or development drilling is planned and/or development studies/plans are in various stages of completion.

The Company has entered into an agreement to sell 30% of its working interest in most of its oil and gas properties in Malaysia. The sale price of $2.0 billion is subject to normal closing costs and adjustments. The sale is expected to close in two phases, with 20% being completed in December 2014 and 10% being completed in the first quarter 2015.

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

Note C – Inventories

Inventories are carried at the lower of cost or market. For the Company's U.K. refining and marketing operations reported as discontinued operations, the cost of crude oil and finished products is predominantly determined on the last-in, first-out (LIFO) method. At September 30, 2014 and December 31, 2013, the carrying value of inventories under the LIFO method was $133.0 million and $268.6 million, respectively, less than such inventories would have been valued using the first-in, first-out (FIFO) method. These inventories are included in assets held for sale on the Consolidated Balance Sheet.

Note D – Discontinued Operations

The Company has previously announced its intention to sell its U.K. refining and marketing operations. The Company has accounted for this U.K. downstream business as discontinued operations for all periods presented, including a reclassification of 2013 operating results and cash flows for this business to discontinued operations. The

U.K. downstream operations were previously reported as a separate segment within the Company's former refining and marketing business. On September 30, 2014, the Company completed the sale of its U.K. retail marketing operations. The Company received the net proceeds of $232.7 million upon open of banking operations on October 1, 2014. Although Murphy had previously signed an agreement to sell the Milford Haven, Wales, refinery and terminal assets, the transaction could not be completed by the October 31, 2014 deadline. The refinery is currently in a period of shut-down and will be decommissioned and operated as a petroleum storage and distribution terminal while the Company seeks a buyer for the terminal facility and three inland terminals. The Company realized an after-tax gain of $98.7 million on the sale of the U.K. retail marketing operation in the third quarter 2014, but this gain was essentially offset by a similar reduction in the carrying value of its held for sale Milford Haven, Wales refinery.

On August 30, 2013, Murphy Oil Corporation (the "Company") distributed 100% of the outstanding common stock of Murphy USA Inc. ("MUSA") to its shareholders in a generally tax-free spin-off for U.S. federal income tax purposes. Prior to the separation, MUSA held all of the Company's U.S. downstream operations, including retail gasoline stations and other marketing assets, plus two ethanol production facilities. The shares of MUSA common stock are traded on the New York Stock Exchange under the ticker symbol "MUSA." The Company has no continuing involvement with MUSA operations. Accordingly, the operating results and the cash flows for these former U.S. downstream operations have been reported as discontinued operations in the 2013 consolidated financial statements. The U.S. downstream operations were previously reported as a separate segment within the Company's former refining and marketing business.

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

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Contd.)

Note D – Discontinued Operations (Contd.)

The results of operations associated with these discontinued operations for the three-month and nine-month periods ended September 30, 2014 and 2013 were as follows:

	Three Months Ended September 30,		Nine Months Ended September 30,	
(Thousands of dollars)	2014	2013	2014	2013
Revenues	$ 509,037	4,502,100	2,752,557	15,981,683
Income before income taxes, including pretax gain on disposals of $130,568 during the nine-month period in 2013	$ (27,163)	38,329	(61,396)	355,668
Income tax expense (benefit)	(1,813)	18,598	(8,757)	15,266
Income (loss) from discontinued operations	$ (25,350)	19,731	(52,639)	340,402

The following table presents the carrying value of the major categories of assets and liabilities of U.K. refining and marketing operations reflected as held for sale on the Company's Consolidated Balance Sheets at September 30, 2014 and December 31, 2013.

(Millions of dollars)	September 30, 2014	December 31, 2013
Current assets		
Cash	$ 197,607	301,302
Accounts receivable	378,804	302,059
Inventories	85,757	254,240
Other	73,707	86,131
Total current assets held for sale	$ 735,875	943,732
Non-current assets		
Property, plant and equipment, net	$ 37,304	360,347
Other	23,203	21,057
Total non-current assets held for sale	$ 60,507	381,404

Current liabilities		
Accounts payable	$ 185,846	637,432
Other	–	1,708
Total current liabilities associated with assets held for sale	$ 185,846	639,140
Non-current liabilities		
Deferred income taxes payable	$ 70,424	68,096
Other	4,613	27,448
Total non-current liabilities associated with assets held for sale	$ 75,037	95,544

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Contd.)

Note E – Financing Arrangements and Debt

The Company has a $2.0 billion committed credit facility that expires in June 2017. Borrowings under the facility bear interest at 1.25% above LIBOR based on the Company's current credit rating as of September 30, 2014. In addition, facility fees of 0.25% are charged on the full $2.0 billion commitment. The Company also had unused uncommitted credit facilities that totaled approximately $270 million at September 30, 2014. These uncommitted facilities may be withdrawn by the various banks at any time. 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. Current maturities and long-term debt on the Consolidated Balance Sheet included $39.6 million and $341.3 million associated with this lease at September 30, 2014.

Note F – Cash Flow Disclosures

Additional disclosures regarding cash flow activities are provided below.

	Nine Months Ended September 30,	
(Thousands of dollars)	2014	2013
Net (increase) decrease in operating working capital other than cash and cash equivalents:		
Decrease (increase) in accounts receivable	$ 29,586	(75,735)
Increase in inventories	(3,326)	(51,279)
Increase in prepaid expenses	(2,235)	(52,793)
Decrease in deferred income tax assets	1,290	40,145
Increase (decrease) in accounts payable and accrued liabilities	59,369	(84,344)
Increase (decrease) in current income tax liabilities	(77,744)	199,461

Total	$ 6,940	(24,545)
Supplementary disclosures (including discontinued operations):		
Cash income taxes paid	$ 438,309	414,676
Interest paid, net of amounts capitalized	44,657	1,077

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.

Effective with the spin-off of Murphy's former U.S. retail marketing operation, Murphy USA Inc. (MUSA) on August 30, 2013, significant modifications were made to the U.S. defined benefit pension plan. Certain Murphy employees' benefits under the U.S. plan were frozen at that time. No further benefit service will accrue for the affected employees; however, the plan will recognize future eligible earnings after the spin-off date. In addition, all previously unvested benefits became fully vested at the spin-off date. For those affected active employees of the Company, additional U.S. retirement plan benefits will accrue in future periods under a cash balance formula. Employees hired after August 30, 2013 will only accrue plan benefits under the cash balance formula. Upon the spin-off of MUSA, Murphy retained all vested pension defined benefit and other postretirement benefit obligations

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Contd.)

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

associated with current and former employees of this separated business. No additional benefit will accrue for any employees of MUSA under the Company's retirement plan after the spin-off date.

The table that follows provides the components of net periodic benefit expense for the three-month and

nine-month periods ended September 30, 2014 and 2013.

	Three Months Ended September 30,			
	Pension Benefits		Other Postretirement Benefits	
(Thousands of dollars)	2014	2013	2014	2013
Service cost	$ 6,208	7,252	672	1,232
Interest cost	8,239	8,450	1,278	1,352
Expected return on plan assets	(8,506)	(8,257)	–	–
Amortization of prior service cost	227	262	(20)	(35)
Amortization of transitional asset	208	125	1	2
Recognized actuarial loss	1,735	4,591	59	391
Special termination benefits	–	849	–	–
Curtailments	–	1,366	–	(443)
Net periodic benefit expense	$ 8,111	14,638	1,990	2,499

	Nine Months Ended September 30,			
	Pension Benefits		Other Postretirement Benefits	
(Thousands of dollars)	2014	2013	2014	2013
Service cost	$ 19,048	21,949	2,016	3,629
Interest cost	24,707	22,581	3,833	3,865
Expected return on plan assets	(25,514)	(21,526)	–	–
Amortization of prior service cost	680	841	(61)	(121)
Amortization of transitional asset	628	366	4	6
Recognized actuarial loss	5,201	12,882	177	1,321
Special termination benefits	–	849	–	–
Curtailments	–	1,366	–	(443)

Net periodic benefit expense	$ 24,750	39,308	5,969	8,257

During the nine-month period ended September 30, 2014, the Company made contributions of $42.2 million to its defined benefit pension and postretirement benefit plans. Remaining funding in 2014 for the Company's defined benefit pension and postretirement plans is anticipated to be $9.7 million.

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 (RSU), 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.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Contd.)

Note H – Incentive Plans (Contd.)

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.

On February 4, 2014, the Committee granted stock options for 772,900 shares at an exercise price of $55.82 per share. The Black-Scholes valuation for these awards was $12.84 per option. The Committee also granted 464,300 performance-based RSU and 233,400 time-based RSU on that date. The fair value of the performance-based RSU, using a Monte Carlo valuation model, ranged from $33.90 to $51.30 per unit. The fair value of time-based RSU was estimated based on the fair market value of the Company's stock on the date of grant, which was $55.82 per share. Additionally, on February 4, 2014, the Committee granted 183,200 SAR and 170,900 units of cash-settled RSU (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 value of these SAR was equivalent to the stock options granted, while the initial value of RSU-C was equivalent to equity-settled restricted stock units granted. On February 5, 2014, the Committee granted 43,848 shares of time-based RSU 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 at $55.20 per unit.

Beginning January 1, 2014, all stock option exercises are non-cash transactions for the Company. The employee will receive net shares, after applicable withholding taxes, upon each exercise. Cash received from options exercised under all share-based payment arrangements for the nine-month period ended September 30, 2013 was $2.8 million. The actual income tax benefit realized for the tax deductions from option exercises of the share-based payment arrangements totaled $3.8 million and $6.3 million for the nine-month periods ended September 30, 2014 and 2013, respectively.

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

	Nine Months Ended September 30,	
(Thousands of dollars)	2014	2013

Compensation charged against income before tax benefit	$ 45,373	51,085
Related income tax benefit recognized in income	14,036	14,945

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 nine-month periods ended September 30, 2014 and 2013. The following table reconciles the weighted-average shares outstanding used for these computations.

	Three Months Ended September 30,		Nine Months Ended September 30,	
(Weighted-average shares)	2014	2013	2014	2013
Basic method	177,535,503	186,938,328	179,259,573	188,914,000
Dilutive stock options and restricted stock units	1,320,575	1,399,183	1,318,512	1,331,166
Diluted method	178,856,078	188,337,511	180,578,085	190,245,166

The following table reflects certain options to purchase shares of common stock that were outstanding during the 2014 and 2013 periods but were not included in the computation of diluted EPS above because the incremental shares from assumed conversion were antidilutive.

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2014	2013	2014	2013
Antidilutive stock options excluded from diluted shares	1,998,009	1,165,464	1,855,667	941,155
Weighted average price of these options	$ 58.53	$ 54.56	$ 58.80	$ 54.40

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Contd.)

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 nine-month periods in 2014 and 2013, the Company's effective income tax rates were as follows:

	2014	2013
Three months ended September 30	31.6 %	42.8 %
Nine months ended September 30	43.7 %	44.6 %

The effective tax rates for most 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 effective tax rate for the three-month period ended September 30, 2014 was below the U.S. statutory tax rate due to a $34.3 million U.S. tax benefit associated with costs in Kurdistan recognized upon wind-up of operations in that country. Excluding the benefit for Kurdistan, the effective tax rate for the three-month period ended September 30, 2014 was 40.3%.

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 September 30, 2014, the earliest years remaining open for audit and/or settlement in our major taxing jurisdictions are as follows: United States – 2010; Canada – 2008; United Kingdom – 2012; and

Malaysia – 2007.

Note K – Financial Instruments and Risk Management

Murphy 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 unrealized gains and losses on these derivative contracts in its Consolidated Statements of Income. Certain interest rate derivative contracts were accounted for as hedges and the loss associated with settlement of these contracts was deferred in Accumulated Other Comprehensive Income. This loss is being reclassified to Interest Expense in the Consolidated Statements of Income over the period until the associated notes mature in 2022.

Commodity Purchase Price Risks

The Company is subject to commodity price risk related to crude oil it will produce and sell in the remainder of 2014. The Company has entered into a series of West Texas Intermediate (WTI) crude oil fixed-price swap financial contracts covering a portion of its Eagle Ford Shale production from October 2014 through December 2014. Under these contracts, which mature monthly, the Company will pay the average monthly price in effect and will receive the fixed contract prices. WTI open contracts at September 30, 2014 were as follows:

Dates	Volumes (barrels per day)	Swap Prices
October – December 2014	22,000	$ 93.26 per barrel

The fair value of these open commodity derivative contracts was a net asset of $6.2 million at September 30, 2014.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Contd.)

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

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 September 30, 2013 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 September 30, 2013 were approximately $76.0 million. There were no open ringgit contracts at September 30, 2014. Short-term derivative instrument contracts totaling $15.0 million and $28.0 million U.S. dollars were also outstanding at September 30, 2014 and 2013, 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 $0.2 million and $4.1 million for the nine-month periods ended September 30, 2014 and September 30, 2013, respectively.

At September 30, 2014 and December 31, 2013, the fair value of derivative instruments not designated as hedging instruments are presented in the following table.

	September 30, 2014		December 31, 2013	
(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	$ 6,152	Accounts receivable	$ 1,970
Foreign Currency	Accounts payable	(189)	Accounts payable	(1,038)

For the three-month and nine-month periods ended September 30, 2014 and 2013, 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)

(Thousands of dollars)	Statement of Income	Three Months Ended September 30,		Nine Months Ended September 30,	
Type of Derivative Contract	Location	2014	2013	2014	2013
Commodity	Sales and other operating revenues	$ 37,305	(1,305)	(17,150)	(1,305)
Commodity	Discontinued operations	–	2,980	–	1,604
Foreign exchange	Interest and other income (loss)	(838)	(2,557)	4,062	(6,703)
		$ 36,467	(882)	(13,088)	(6,404)

Interest Rate Risks

In 2011 the Company entered into a series of derivative contracts known as forward starting interest rate swaps to manage interest rate risk associated with $350 million of 10-year notes that were sold in May 2012. These interest rate swaps matured in May 2012. Under hedge accounting rules, the Company deferred a loss on these contracts to match the payment of interest on these notes through 2022. During each of the nine-month periods ended September 30, 2014 and 2013, $2.2 million of the deferred loss on the interest rate swaps was charged to income as a component of Interest Expense. The remaining loss deferred on these matured contracts at September 30, 2014 was $22.6 million, which is recorded, net of income taxes of $7.9 million, in Accumulated Other Comprehensive Income in the Consolidated Balance Sheet. The Company expects to charge approximately $0.8 million of this deferred loss to income in the form of interest expense during the remaining three months of 2014.

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.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Contd.)

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

The carrying value of assets and liabilities recorded at fair value on a recurring basis at September 30, 2014 and December 31, 2013 are presented in the following table.

	September 30, 2014				December 31, 2013			
(Thousands of dollars)	Level 1	Level 2	Level 3	Total	Level 1	Level 2	Level 3	Total
Assets:								
Commodity derivative contracts	$ –	6,152	–	6,152	–	1,970	–	1,970
Liabilities:								
Nonqualified employee savings plans	$ 13,979	–	–	13,979	13,267	–	–	13,267
Foreign currency exchange derivative contracts	–	189	–	189	–	1,038	–	1,038
	$ 13,979	189	–	14,168	13,267	1,038	–	14,305

The fair value of West Texas Intermediate (WTI) crude oil derivative contracts was determined based on active market quotes for WTI crude oil at the balance sheet dates. The fair value of foreign exchange derivative contracts was based on market quotes for similar contracts at the balance sheet dates. The income effect of changes in the fair value of crude oil derivative contracts is recorded in Sales and Other Operating Revenues 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 in the Consolidated Statements of Income.

The Company offsets certain assets and liabilities related to derivative contracts when the legal right of offset exists. There were no offsetting positions recorded at September 30, 2014 and December 31, 2013.

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Contd.)

Note L – Accumulated Other Comprehensive Income

The components of Accumulated Other Comprehensive Income (Loss) (AOCI) on the Consolidated Balance Sheets at December 31, 2013 and September 30, 2014 and the changes during the nine-month period ended September 30, 2014 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 December 31, 2013	$	305,192	(116,956)		(16,117)		172,119
Components of other comprehensive income (loss):							
Before reclassifications to income		(195,374)	306		–		(195,068)
Reclassifications to income		–	3,690	2	1,450	3	5,140
Net other comprehensive income (loss)		(195,374)	3,996		1,450		(189,928)
Balance at September 30, 2014	$	109,818	(112,960)		(14,667)		(17,809)

1All amounts are presented net of income taxes.

2Reclassifications before taxes of $5,637 for the nine-month period ended September 30, 2014 are included in the computation of net periodic benefit expense. See Note G for additional information. Related income taxes of $1,947 for the nine-month period ended September 30, 2014 are included in Income tax expense.

3Reclassifications before taxes of $2,222 for the nine-month period ended September 30, 2014 are included in Interest expense. Related income taxes of $772 for the nine-month period ended September 30, 2014 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.

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

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Contd.)

Note M – Environmental and Other Contingencies (Contd.)

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. Certain of these historical properties are in various stages of negotiation, investigation, and/or cleanup and the Company is investigating the extent of any such liability and the availability of applicable defenses. The Company has retained certain liabilities related to environmental matters at formerly owned U.S. refineries that were sold in 2011. The Company also obtained insurance covering certain levels of environmental exposures related to past operations of these refineries. 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) formerly considered the Company to be a Potentially Responsible Party (PRP) at one Superfund site. Based on evidence provided by the Company, the EPA has determined that the Company is no longer considered a PRP at this site.

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.

Note N – Commitments

The Company has entered into forward sales contracts to mitigate the price risk for a portion of its 2014 heavy oil and 2014 through 2016 natural gas sales volumes in Western Canada. The heavy oil blend sales contracts call for deliveries of 4,000 barrels per day in October through December 2014 that achieve netback values that average Cdn$53.63 per barrel. The natural gas contracts call for deliveries from October through December 2014 that average approximately 110 million cubic feet per day at prices averaging Cdn$4.04 per MCF, with the contracts calling for delivery at the NOVA inventory transfer sales point. The Company also has natural gas sales contracts calling for deliveries in 2015 and 2016 of approximately 65 million cubic feet per day and 10 million cubic feet per day, respectively, at prices that average Cdn$4.13 per MCF for both periods. These oil and natural gas contracts have been accounted for as normal sales for accounting purposes.

Note O – New Accounting Principles

In August 2014, the Financial Accounting Standards Board (FASB) issued an Accounting Standards Update (ASU), requiring, when applicable, disclosures regarding uncertainties about an entity's ability to continue as a going concern. During the preparation of quarterly and annual financial statements, management should evaluate whether conditions or events exist that raise substantial doubt about the entity's ability to continue as a going concern within one year after the date the financial statements are issued. If this evaluation indicates that it is probable that an entity will be unable to meet its obligations when they become due within one year of the financial statement issuance date, management must evaluate whether its mitigation plans will alleviate the substantial doubt of continuing as a going concern. If substantial doubt exists, regardless of whether the mitigation plan alleviates the concern, additional disclosures are required in the financial statements addressing the conditions or events that raise substantial doubt, management's evaluation of the significance of those conditions or events, and management's mitigation plans. This new guidance will become effective for the Company for all reporting periods beginning in 2016. Early application is permitted. Company management currently does not expect that this new guidance will have a significant effect on its consolidated financial statements when adopted.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Contd.)

Note O – New Accounting Principles (Contd.)

In May 2014, the FASB issued an ASU addressing recognition of revenue from contracts with customers. When adopted, this guidance will supersede current revenue recognition rules currently followed by the Company. The core principle of the new ASU is that an entity should recognize revenue to depict the transfer of promised goods or services to customers that reflects the consideration to which the entity expects to be entitled in exchange for those goods or services. The ASU provides five steps for an entity to apply in recognizing revenue, including: (1) identify the customer contract; (2) identify the contractual performance obligations; (3) determine the transaction price; (4) allocate the transaction price to the contractual performance obligations; and (5) recognize revenue when the performance obligation is satisfied. The new ASU also requires additional disclosures regarding significant contracts with customers. The new ASU will be effective for the Company on January 1, 2017, and early adoption is not permitted. For transition purposes, the new ASU permits either (a) a retrospective application to all years presented, or (b) an alternative transition method whereby the new guidance is only applied to contracts not completed at the date of initial application. The vast majority of the Company's revenue is recognized when oil and natural gas produced by the Company is delivered and legal ownership of these products has transferred to the purchaser. Based on the Company's present understanding, the accounting for oil and gas sales revenue is not expected to be significantly altered by the new ASU. The Company has not yet selected which transition method it will use.

In April 2014, the FASB issued an ASU that will change the requirements for reporting discontinued operations after its adoption. Under the new guidance, only disposals of components of an entity that represent a strategic shift that has or will have a major effect on an entity's operations and financial results will be reported as discontinued operations in the financial statements. Under prior guidance, a component of an entity that is a reportable segment, an operating segment, a reporting unit, a subsidiary, or an asset group that has been or will be eliminated from ongoing operations and for which the Company will not have any significant continuing involvement with the component after the disposal was generally reported as discontinued operations. The FASB anticipates that fewer component disposals will be reported as discontinued operations under the new guidance. The new guidance also requires expanded disclosures about discontinued operations. The new guidance will be effective for the Company beginning in 2015. The new guidance is not to be applied to a component that is classified as held for sale before the effective date of the guidance.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Contd.)

Note P – Business Segments

(Millions of dollars)	Total Assets at September 30, 2014	Three Months Ended September 30, 2014 External Revenues	Three Months Ended September 30, 2014 Income (Loss)	Three Months Ended September 30, 2013[1] External Revenues	Three Months Ended September 30, 2013[1] Income (Loss)
Exploration and production[2]					
United States	$ 5,620.2	667.6	130.5	512.0	151.3
Canada	3,933.0	246.9	40.4	316.4	77.3
Malaysia	6,100.0	516.4	148.0	538.0	183.8
Other	135.1	–	(7.5)	–	(148.2)
Total exploration and production	15,788.3	1,430.9	311.4	1,366.4	264.2
Corporate	1,254.4	2.1	(40.4)	53.1	0.8
Assets/revenue/income from continuing operations	17,042.7	1,433.0	271.0	1,419.5	265.0
Discontinued operations, net of tax	803.1	–	(25.3)	–	19.8
Total	$ 17,845.8	1,433.0	245.7	1,419.5	284.8

(Millions of dollars)	Nine Months Ended September 30, 2014 External Revenues	Nine Months Ended September 30, 2014 Income (Loss)	Nine Months Ended September 30, 2013[1] External Revenues	Nine Months Ended September 30, 2013[1] Income (Loss)
Exploration and production[2]				
United States	$ 1,660.4	335.3	1,365.1	368.0
Canada	807.4	160.9	894.0	142.3
Malaysia	1,592.2	482.6	1,652.7	602.5
Other	(0.2)	(256.0)	68.9	(326.5)
Total exploration and production	4,059.8	722.8	3,980.7	786.3
Corporate	8.6	(139.8)	61.7	(78.7)
Revenue/income from continuing operations	4,068.4	583.0	4,042.4	707.6
Discontinued operations, net of tax	–	(52.6)	–	340.4
Total	$ 4,068.4	530.4	4,042.4	1,048.0

[1]Reclassified to conform to current presentation.

[2]Additional details about results of oil and gas operations are presented in the tables on pages 27 and 28.

Due to the shutdown of production operations in Republic of the Congo, the Company now includes the results of these operations in the Other exploration and production segment in the above table.

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

Overall Review

On September 30, 2014, the Company announced the signing of an agreement to sell 30% of its various interests in several production sharing contracts in Malaysia. The sales price for these various interests is $2.0 billion subject to customary closing costs and adjustments, with the effective date of the sale as of January 1, 2014. The sale is expected to close in two phases, with the first phase equal to 20% completing in December 2014 and the remaining 10% completing in the first quarter 2015. The Company currently expects to use the proceeds of the Malaysian asset sale for a combination of asset acquisitions, debt reduction, share repurchases and/or capital expenditures.

Also, on September 30, 2014, the Company completed the sale of its U.K. retail marketing assets. The Company, as previously announced, had signed an agreement to sell its Milford Haven, Wales, refinery and terminal assets. However, the Company was unable to complete the transaction by the October 31, 2014 deadline. The refinery is currently in a period of shut-down and will be decommissioned and operated as a petroleum storage and distribution terminal while the Company seeks a buyer for the terminal facility and three inland terminals.

On August 6, 2014, the Company announced that its Board of Directors had authorized a $500 million share repurchase program. Through the filing date of this Form 10-Q report, the Company has not repurchased any of its shares under this share buyback program.

During October and early November 2014, worldwide benchmark oil prices declined significantly compared to the average benchmark prices during the third quarter 2014. Should these lower benchmark oil prices remain, the Company would expect its net income and cash flow to be adversely affected in the fourth quarter 2014.

Results of Operations

Murphy’s income by type of business is presented below.

Income (Loss)

(Millions of dollars)	Three Months Ended September 30, 2014	2013	Nine Months Ended September 30, 2014	2013
Exploration and production	$ 311.4	264.2	722.8	786.3
Corporate and other	(40.4)	0.8	(139.8)	(78.7)
Income from continuing operations	271.0	265.0	583.0	707.6
Discontinued operations	(25.3)	19.8	(52.6)	340.4
Net income	$ 245.7	284.8	530.4	1,048.0

Murphy's net income in the third quarter of 2014 was $245.7 million ($1.37 per diluted share) compared to net income of $284.8 million ($1.51 per diluted share) in the third quarter of 2013. Income from continuing operations increased from $265.0 million ($1.41 per diluted share) in the 2013 quarter to $271.0 million ($1.51 per diluted share) in 2014. In the 2014 third quarter, the Company's exploration and production continuing operations earned $311.4 million, up from $264.2 million in the 2013 quarter. Exploration and production income in the 2014 quarter was favorably impacted compared to 2013 by lower costs for exploration activities, U.S. tax benefits on foreign exploration activities and higher total hydrocarbon sales volumes, but was unfavorably affected by lower oil sales prices and higher extraction costs. The corporate function had after-tax costs of $40.4 million in the 2014 third quarter compared to an after-tax benefit of $0.8 million in the 2013 period with the unfavorable variance in the current period due mostly to foreign currency exchange effects and higher net interest expense. The 2014 third quarter included a loss from discontinued operations of $25.3 million ($0.14 per diluted share) related to refining and marketing operations in the U.K. Discontinued operations reflected a profit of $19.8 million ($0.10 per diluted share) in the third quarter 2013, including earnings of $33.0 million from U.S. retail marketing operations that were spun off to shareholders on August 30, 2013. Discontinued operations in the third quarters of 2014 and 2013 included losses from U.K. refining and marketing operations of $25.4 million and $12.9 million, respectively.

For the first nine months of 2014, net income totaled $530.4 million ($2.94 per diluted share) compared to net income of $1,048.0 million ($5.51 per diluted share) for the same period in 2013. Continuing operations earned

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

Results of Operations (Contd.)

$583.0 million ($3.23 per diluted share) in the first nine months of 2014, down from $707.6 million ($3.72 per diluted share) in the 2013 period. In the first nine months of 2014, the Company's exploration and production operations earned $722.8 million from continuing operations compared to $786.3 million in the same period of 2013. Exploration and production earnings in 2014 were below the 2013 period primarily due to higher exploration and extraction expenses plus lower average realized oil prices. Corporate after-tax costs were $139.8 million in the 2014 period compared to after-tax costs of $78.7 million in the 2013 period as the current period had an unfavorable variance for the effects of foreign currency exchange and higher interest expense. Earnings in the first nine months of 2014 included a loss from discontinued operations of $52.6 million ($0.29 per diluted share) compared to a profit of $340.4 million ($1.79 per diluted share) in the 2013 period. Discontinued operating results for the Company's U.K. refining and marketing operations were a net loss of $52.4 million in the nine months ended September 30, 2014 and a net loss of $22.7 million during the same period in 2013. Additionally, discontinued operations in the 2013 period included earnings of $140.3 million from U.S. retail marketing operations spun off on August 30, 2013, plus after-tax profit of $222.8 million for the U.K. oil and gas business, which was primarily generated by a gain on sale of these assets.

Exploration and Production

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

	Income (Loss)			
	Three Months Ended September 30,		Nine Months Ended September 30,	
(Millions of dollars)	2014	2013	2014	2013
Exploration and production				
United States	$ 130.5	151.3	335.3	368.0
Canada	40.4	77.3	160.9	142.3
Malaysia	148.0	183.8	482.6	602.5
Other International	(7.5)	(148.2)	(256.0)	(326.5)
Total	$ 311.4	264.2	722.8	786.3

Third quarter 2014 vs. 2013

United States exploration and production operations reported a profit of $130.5 million in the third quarter of 2014 compared to a profit of $151.3 million in the 2013 quarter. Earnings were $20.8 million lower in the 2014 quarter compared to the same period in 2013 as higher exploration expenses were partially offset by higher oil and natural gas sales volumes and a favorable impact from the unrealized change in fair value of crude oil derivative contracts. Revenue in the U.S. rose $155.6 million in the third quarter 2014 primarily due to higher oil and natural gas volumes produced and sold in the Eagle Ford Shale in South Texas, where a significant development drilling program is ongoing with seven active land rigs. Revenue in 2014 was unfavorably affected by $5.4 million for payments under matured West Texas Intermediate (WTI) oil derivative contracts, which reduced the realized sales price for Eagle Ford Shale crude oil by $1.22 per barrel. But revenues for the quarter included an unrealized benefit of $43.1 million for an improvement in the fair value of open crude oil sales derivative contracts covering certain fourth quarter 2014 production in the Eagle Ford Shale. These oil derivative contracts are marked to market each quarter-end. U.S. natural gas sales prices were down slightly compared to a year earlier. Lease operating, production tax and depreciation expenses increased $21.6 million, $6.1 million and $78.3 million, respectively, in 2014 compared to 2013 due to both higher production in the Eagle Ford Shale area and new production at the Dalmatian field in the Gulf of Mexico. Exploration expense was up $76.0 million in 2014 primarily related to unsuccessful exploratory drilling at the Titan prospect in the Gulf of Mexico. Selling and general expenses in the 2014 period increased $2.7 million from the prior year primarily due to higher staffing costs.

Operations in Canada had earnings of $40.4 million in the third quarter 2014 compared to earnings of $77.3 million in the 2013 quarter. Canadian earnings were $36.9 million lower in the 2014 quarter due to weaker results for both conventional oil and natural gas operations and synthetic oil operations. Earnings for conventional operations were $26.8 million lower in 2014 mostly due to less oil sales volumes at the Terra Nova and Hibernia oil fields, plus lower oil sales prices. Sales prices for crude oil declined in all Canadian producing areas in the third quarter of 2014 compared to the 2013 quarter. However, natural gas sales prices increased in 2014, which served to partially offset the decline in oil prices. Oil production for conventional operations declined in Canada in the 2014 period compared to 2013 primarily due to lower volume at the Seal heavy oil area and lower volumes produced at both the Hibernia and Terra Nova fields, offshore Newfoundland. Natural gas sales volumes decreased in 2014 due to lower production in the Tupper area of Western Canada. Depreciation expense for conventional oil and

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

Results of Operations (Contd.)

Exploration and Production (Contd.)

Third quarter 2014 vs. 2013 (Contd.)

natural gas operations in Canada was lower in 2014 by $19.2 million, due primarily to reduced oil and natural gas production volumes in 2014. Synthetic operating results were lower by $10.1 million in the third quarter of 2014 due to weaker realized oil prices. Production expenses associated with synthetic operations were slightly reduced in the 2014 quarter due to lower maintenance costs, while depreciation expense rose slightly due to a somewhat higher depreciation unit rate.

Operations in Malaysia reported earnings of $148.0 million in the 2014 quarter compared to earnings of $183.8 million during the same period in 2013. Earnings were down $35.8 million in 2014 in Malaysia primarily from lower realized sales prices for oil and natural gas produced offshore Sarawak. Crude oil production and sales volumes in Malaysia were higher in the 2014 quarter, primarily from new oil fields offshore Sarawak and at Siakap North, offshore Sabah. However, oil production and sales volumes were lower in the 2014 quarter at the Kikeh field, offshore Sabah. The 2014 quarter included a larger impact from contractually required revenue sharing with the local government, which lowered realized oil and natural gas prices at fields offshore Sarawak. Lease operating expense decreased in the 2014 period by $10.1 million primarily due to lower overall oil sales volumes for oil fields in Block K. Depreciation expense was $44.6 million more in 2014 compared to the 2013 quarter primarily due to the current quarter including a higher cost mix associated with new oil production offshore Sarawak and at the Siakap North field, offshore Sabah. Selling and general expense rose $2.0 million in 2014 due to higher staffing costs being only partially recovered through joint operating agreements with partners.

Other international operations reported a loss of $7.5 million in the third quarter of 2014 compared to a loss of $148.2 million in the 2013 quarter. The $140.7 million improvement in the current quarter was primarily related to lower exploration expenses of $104.7 million and a realized U.S. tax benefit of $34.3 million related to exiting the Central Dohuk block in the Kurdistan region of Iraq. The 2013 quarter had higher seismic costs associated with prospects in Vietnam, Australia, Namibia and other areas along the Atlantic Margin, and higher dry hole expense in Cameroon.

Total hydrocarbon production averaged 229,759 barrels of oil equivalent per day in the 2014 third quarter, which was a Company record and represented an 11% increase from the 207,281 barrel equivalents per day produced in the 2013 quarter. Average crude oil and condensate production was 144,934 barrels per day in the third quarter of 2014 compared to 133,355 barrels per day in the third quarter of 2013. Crude oil production increased in the Eagle Ford Shale area of South Texas in 2014 due to a significant ongoing development drilling and completion program. Crude oil production in the Gulf of Mexico was higher in the 2014 quarter due to start-up of the Dalmatian field early in the year. Heavy oil production from the Seal area in Western Canada was lower in 2014 due to well declines. Oil production offshore Eastern Canada was lower during 2014 primarily due to more downtime for equipment repairs. Oil production offshore Sarawak increased in the 2014 quarter due to ramp-up of production at new oil fields. Oil production was lower in Block K in the 2014 quarter due to well decline at the Kikeh field, partially offset by higher oil produced at the new Siakap North field. On a worldwide basis, the Company's crude oil and condensate prices averaged $89.36 per barrel in the third quarter 2014 compared to $98.54 per barrel in the 2013 period. Total production of natural gas liquids (NGL) was 10,923 barrels per day in the 2014 third quarter compared to 4,720 barrels per day in the same 2013 period. The increase in NGL was primarily associated with an ongoing drilling program in the Eagle Ford Shale and start-up of the Dalmatian field in the Gulf of Mexico in early 2014. The average sales price for U.S. NGL was $27.89 per barrel in the 2014 quarter compared to $28.14 per barrel in 2013. Natural gas sales volumes averaged 443 million cubic feet per day in the third quarter 2014, up from 415 million cubic feet per day in the 2013 quarter. Natural gas sales volumes increased in the U.S. in 2014 due to ongoing development drilling in the Eagle Ford Shale and start-up of the Dalmatian field in the Gulf of Mexico. The U.S. increase in natural gas sales volumes in 2014 was somewhat offset by lower gas volumes produced in the Tupper area in Western Canada. North American natural gas sales prices averaged $3.63 per thousand cubic feet (MCF) in the 2014 quarter compared to $2.99 per MCF in the same quarter of 2013. The average realized price for natural gas produced in the 2014 quarter at fields offshore Sarawak was $5.11 per MCF, compared to a price of $6.69 per MCF in the 2013 quarter. The Sarawak price declined in 2014 primarily due to higher revenue sharing with the government.

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

Results of Operations (Contd.)

Exploration and Production (Contd.)

Nine months 2014 vs. 2013

U.S. exploration and production operations had income of $335.3 million for the nine months ended September 30, 2014 compared to income of $368.0 million in the 2013 period. The 2014 income reduction of $32.7 million was primarily caused by higher exploration expense, which increased $97.1 million in the current year due to costs for unsuccessful exploration drilling at the Titan prospect in the Gulf of Mexico. The effect of higher exploration expense was partially offset by the impact of higher production volumes in the Eagle Ford Shale and the Gulf of Mexico in 2014. The 2014 period also had higher average realized natural gas sales prices compared to 2013, but realized oil prices were lower year over year. The oil price decline in 2014 was partially caused by net payments of $23.3 million under matured WTI oil contracts. These contracts reduced the Eagle Ford Shale realized oil price by $1.96 per barrel of crude oil produced and sold. Lease operating and production tax expenses in 2014 were higher by $37.3 million and $25.4 million, respectively, compared to 2013 mostly due to production growth in the Eagle Ford Shale. Depreciation expense in 2014 was $166.9 million higher than 2013 due to increased production volumes at both Eagle Ford Shale and Dalmatian. Selling and general expense rose by $14.7 million in 2014 compared to 2013, primarily driven by increased staffing and support costs.

Canadian operations had income of $160.9 million in the first nine months of 2014 compared to income of $142.3 million a year ago. Operating results for conventional operations improved $47.4 million during the first nine months of 2014, but this was somewhat offset by lower earnings of $28.8 million for synthetic oil operations. Sales revenue within conventional operations for 2014 were below the prior year as the effect of lower oil and natural gas sales volumes more than offset better heavy oil and natural gas sales prices. Lease operating and depreciation expenses for conventional operations were lower by $12.2 million and $56.4 million, respectively, in 2014 mostly related to lower sales volumes in the current year. Exploration expenses in 2014 were $32.2 million less than 2013 primarily due to dry hole costs in the prior year in the Muskwa Shale area of Northern Alberta. Impairment expense of $21.6 million in 2013 related to a write down of wells that performed below expectation in the Kainai area of Southern Alberta. Synthetic oil operations earnings declined in 2014 primarily due to lower production volumes caused by more downtime for equipment repairs during the 2014 period. Additionally, synthetic oil operations incurred higher lease operating costs of $11.1 million in the current year due to a combination of higher natural gas costs used in production operations and more equipment repair costs.

Malaysia operations earned $482.6 million in the first nine months of 2014 compared to earnings of $602.5 million in the 2013 period. Earnings were down $119.9 million in 2014 primarily due to lower crude oil sales volumes at fields offshore Sabah, lower realized sales prices for Sarawak natural gas production, and higher extraction costs. Higher crude oil volumes sold at new fields offshore Sarawak partially offset these unfavorable variances. The 2014 period experienced higher revenue sharing with the local government under the existing production sharing contracts covering Sarawak oil and natural gas production volumes. Lease operating expense in 2014 was higher than in 2013 by $19.4 million primarily due to a benefit in the prior year for a retroactive processing fee adjustment related to gas liquids processing. Depreciation expense was up $106.4 million in 2014 primarily due to higher average per-unit depreciation rates for new Malaysian production volumes at offshore Sarawak fields and at the Siakap North field, offshore Sabah. Selling and general expenses rose $9.8 million in 2014 compared to the prior year due to higher staffing costs and lower amounts charged to partners associated with less development activities compared to the prior year.

Other international operations reported a loss of $256.0 million in the first nine months of 2014 compared to a loss of $326.5 million in the 2013 period. The 2014 period included U.S. income tax benefits of $34.3 million associated with exiting the Central Dohuk block in the Kurdistan region of Iraq. The 2013 period also had nonrecurring losses associated with former oil production operations in Republic of the Congo. Exploration expenses were $17.1 million lower in 2014, but this was mostly offset by higher selling and general expense of $11.5 million in the current period.

Total worldwide production averaged 214,888 barrels of oil equivalent per day during the nine months ended September 30, 2014, more than a 4% increase from the 205,539 barrels of oil equivalent produced in the same period in 2013. Crude oil and condensate production in the first nine months of 2014 averaged 135,801 barrels per day compared to 130,408 barrels per day a year ago. 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

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

Results of Operations (Contd.)

Exploration and Production (Contd.)

Nine months 2014 vs. 2013 (Contd.)

completion program, more than offset oil production declines in certain other areas. Higher oil volumes produced in the Gulf of Mexico in 2014 was mostly attributable to start-up of the Dalmatian field. Heavy oil production in Canada was lower in 2014 in the Seal area of Western Canada due to well decline. Oil production offshore Eastern Canada was lower in 2014 due to less production at both the Hibernia and Terra Nova fields. Synthetic oil production in Canada also was lower in 2014 due to more downtime for equipment repairs in the current period. Oil production in 2014 in Malaysia was essentially flat in total as higher volumes produced at new oil fields offshore Sarawak and at Siakap North, offshore Sabah, were offset by lower net oil volumes at the Kikeh field. Production at the Kikeh field was unfavorably affected by downtime for hook-up of the Siakap North field and a rig fire in early 2014. Start-up of the non-operated main Kakap field offshore Sabah occurred in October 2014. For the first nine months of 2014, the Company's sales price for crude oil and condensate averaged $93.49 per barrel, down from $95.70 per barrel in 2013. Production of natural gas liquids increased from 3,126 barrels per day in the 2013 nine months to 8,580 barrels per day in 2014. This increase was also mainly attributable to drilling in the Eagle Ford Shale and start-up of the Dalmatian field. The sales price for U.S. natural gas liquids averaged $29.92 per barrel in 2014 compared to $28.31 per barrel in the 2013 nine months. Natural gas sales volumes decreased from 432 million cubic feet per day in 2013 to 423 million cubic feet per day in 2014, with the reduction due to lower gas production volumes in the Tupper area in British Columbia. Natural gas sales volumes in 2014 in the U.S. increased due to drilling in the Eagle Ford Shale area and start-up of the Dalmatian field in the Gulf of Mexico. The average sales price for North American natural gas in the first nine months of 2014 was $3.92 per MCF, up from $3.24 per MCF realized in 2013. Natural gas production at fields offshore Sarawak was sold at an average realized price of $5.67 per MCF in 2014 compared to $6.90 per MCF in 2013. The Sarawak gas price was lower in 2014 primarily due to higher levels of revenue sharing with the local government during the current year.

Additional details about results of oil and gas operations are presented in the tables on pages 27 and 28.

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

Results of Operations (Contd.)

Exploration and Production (Contd.)

Selected operating statistics for the three-month and nine-month periods ended September 30, 2014 and 2013 follow.

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2014	2013	2014	2013
Net crude oil and condensate produced – barrels per day	144,934	133,355	135,801	130,408
Continuing operations	144,934	133,355	135,801	129,542
United States – Eagle Ford Shale	47,745	38,936	43,653	32,819
– Gulf of Mexico and other	16,534	10,937	13,266	12,078
Canada – light	38	41	38	143
– heavy	6,784	8,061	7,433	9,165
– offshore	7,823	10,517	8,216	9,805
– synthetic	11,200	11,075	11,481	12,159
Malaysia – Sarawak	21,679	10,935	19,590	7,652
– Block K	33,131	41,680	32,124	44,448
Republic of the Congo	–	1,173	–	1,273
Discontinued operations – United Kingdom	–	–	–	866
Net crude oil, condensate and gas liquids sold – barrels per day	142,440	129,725	135,942	131,590
Continuing operations	142,440	129,725	135,942	130,759
United States – Eagle Ford Shale	47,745	38,936	43,653	32,819
– Gulf of Mexico and other	16,534	10,937	13,266	12,078
Canada – light	38	41	38	143
– heavy	6,784	8,061	7,433	9,165
– offshore	7,092	10,391	8,605	9,502
– synthetic	11,200	11,075	11,481	12,159
Malaysia – Sarawak	23,660	7,260	21,287	6,852
– Block K	29,387	43,024	30,179	45,786
Republic of the Congo	–	–	–	2,255
Discontinued operations – United Kingdom	–	–	–	831
Net natural gas liquids produced – barrels per day1	10,923	4,720	8,580	3,126
United States – Eagle Ford Shale	6,521	3,188	5,409	1,852
– Gulf of Mexico and other	3,412	880	2,308	644

Canada	23	–	23	–
Malaysia – Sarawak	967	652	840	630
Net natural gas liquids sold – barrels per day1	11,480	4,117	8,625	2,561
United States – Eagle Ford Shale	6,521	3,188	5,409	1,852
– Gulf of Mexico	3,412	880	2,308	644
Canada	23	–	23	–
Malaysia – Sarawak	1,524	49	885	65
Net natural gas sold – thousands of cubic feet per day	443,413	415,235	423,041	432,027
Continuing operations	443,413	415,235	423,041	430,938
United States – Eagle Ford Shale	37,782	20,965	31,890	20,680
– Gulf of Mexico and other	67,137	30,047	50,831	33,380
Canada	151,784	178,666	144,873	179,829
Malaysia – Sarawak	174,958	174,518	166,036	163,776
– Block K	11,752	11,039	29,411	33,273
Discontinued operations – United Kingdom	–	–	–	1,089
Total net hydrocarbons produced – equivalent barrels per day2	229,759	207,281	214,888	205,539
Total net hydrocarbons sold – equivalent barrels per day2	227,822	203,048	215,074	206,156

1U.S. and Canada NGL's were included in the wet natural gas stream during early 2013.

2Natural gas converted on an energy equivalent basis of 6:1.

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

Results of Operations (Contd.)

Exploration and Production (Contd.)

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2014	2013	2014	2013
Weighted average sales prices				
Crude oil and condensate – dollars per barrel				
United States – Eagle Ford Shale	$ 93.56	103.98	95.50	103.44
– Gulf of Mexico and other	97.03	106.39	99.36	106.50
Canada1 – light	85.92	95.87	93.17	85.51
– heavy	57.86	66.25	56.69	47.97
– offshore	97.63	112.04	105.41	108.47
– synthetic	93.55	108.61	96.83	100.24
Malaysia – Sarawak2	80.55	99.86	89.57	98.96
– Block K2	89.00	91.61	95.18	91.46
Republic of the Congo	–	–	–	112.89
Discontinued operations – United Kingdom	–	–	–	108.67
Natural gas liquids – dollars per barrel				
United States – Eagle Ford Shale	$ 26.55	26.82	28.77	26.92
– Gulf of Mexico and other	30.45	32.92	32.60	32.32
Canada1	64.95	–	75.96	–
Malaysia – Sarawak2	68.48	94.01	75.68	104.46
Natural gas – dollars per thousand cubic feet				
United States – Eagle Ford Shale	$ 3.76	3.70	4.17	3.84
– Gulf of Mexico and other	3.60	3.78	4.20	3.86
Canada1	3.61	2.78	3.76	3.05
Malaysia – Sarawak2	5.11	6.69	5.67	6.90
– Block K	0.24	0.23	0.24	0.24
Discontinued operations – United Kingdom	–	–	–	12.32

1U.S. dollar equivalent.

2Prices are net of payments under terms of the respective production sharing contracts.

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

Results of Operations (Contd.)

Exploration and Production (Contd.)

OIL AND GAS OPERATING RESULTS – THREE MONTHS ENDED SEPTEMBER 30, 2014 AND 2013

(Millions of dollars)	United States	Canada Conven-tional	Synthetic	Malaysia	Other	Total
Three Months Ended September 30, 2014						
Oil and gas sales and other operating revenues	$ 667.6	150.1	96.8	516.4	–	1,430.9
Lease operating expenses	84.0	42.6	55.6	83.3	–	265.5
Severance and ad valorem taxes	25.3	1.9	1.4	–	–	28.6
Depreciation, depletion and amortization	234.5	61.9	13.4	185.7	1.3	496.8
Accretion of asset retirement obligations	4.5	1.5	2.4	4.2	–	12.6
Exploration expenses						
Dry holes	66.0	–	–	–	9.8	75.8
Geological and geophysical	3.9	0.1	–	0.5	1.4	5.9
Other	8.9	0.3	–	–	8.6	17.8
	78.8	0.4	–	0.5	19.8	99.5
Undeveloped lease amortization	11.8	4.9	–		1.2	17.9
Total exploration expenses	90.6	5.3	–	0.5	21.0	117.4
Selling and general expenses	24.2	6.3	0.3	3.4	19.5	53.7
Other expenses	0.7	–	–	–	–	0.7
Results of operations before taxes	203.8	30.6	23.7	239.3	(41.8)	455.6
Income tax provisions (benefits)	73.3	7.8	6.1	91.3	(34.3)	144.2
Results of operations (excluding corporate overhead and interest)	$ 130.5	22.8	17.6	148.0	(7.5)	311.4
Three Months Ended September 30, 2013						
Oil and gas sales and other operating revenues	$ 512.0	205.6	110.8	538.0	–	1,366.4
Lease operating expenses	62.4	41.3	56.5	93.4	4.9	258.5
Severance and ad valorem taxes	19.2	2.0	1.2	–	–	22.4
Depreciation, depletion and amortization	156.2	81.1	12.8	141.1	1.0	392.2
Accretion of asset retirement obligations	3.4	1.4	2.6	3.9	1.2	12.5
Exploration expenses						

Dry holes	(0.1)	1.6	–	–	77.7	79.2
Geological and geophysical	3.3	0.1	–	0.4	25.0	28.8
Other	1.5	0.2	–	–	16.9	18.6
	4.7	1.9	–	0.4	119.6	126.6
Undeveloped lease amortization	9.9	5.2	–	–	6.1	21.2
Total exploration expenses	14.6	7.1	–	0.4	125.7	147.8
Selling and general expenses	21.5	5.7	0.3	1.4	15.4	44.3
Results of operations before taxes	234.7	67.0	37.4	297.8	(148.2)	488.7
Income tax provisions	83.4	17.4	9.7	114.0	–	224.5
Results of operations (excluding corporate overhead and interest)	$ 151.3	49.6	27.7	183.8	(148.2)	264.2

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

Results of Operations (Contd.)

Exploration and Production (Contd.)

OIL AND GAS OPERATING RESULTS – NINE MONTHS ENDED SEPTEMBER 30, 2014 AND 2013

(Millions of dollars)	United States	Canada Conven-tional	Synthetic	Malaysia	Other	Total
Nine Months Ended September 30, 2014						
Oil and gas sales and other revenues	$ 1,660.4	504.0	303.4	1,592.2	(0.2)	4,059.8
Lease operating expenses	242.1	123.1	180.1	268.3	–	813.6
Severance and ad valorem taxes	75.7	4.4	3.7	–	–	83.8
Depreciation, depletion and amortization	591.2	192.1	39.8	521.1	3.6	1,347.8
Accretion of asset retirement obligations	12.9	4.6	7.0	12.5	–	37.0
Exploration expenses						
Dry holes	73.5	–	–	–	130.1	203.6
Geological and geophysical	19.7	0.3	–	0.5	54.8	75.3
Other	13.0	0.8	–	–	42.3	56.1
	106.2	1.1	–	0.5	227.2	335.0
Undeveloped lease amortization	37.2	14.8	–	–	3.7	55.7
Total exploration expenses	143.4	15.9	–	0.5	230.9	390.7
Selling and general expenses	71.8	21.4	0.8	11.8	55.6	161.4
Other expenses	1.2	0.1	–	–	–	1.3
Results of operations before taxes	522.1	142.4	72.0	778.0	(290.3)	1,224.2
Income tax provisions (benefits)	186.8	34.8	18.7	295.4	(34.3)	501.4
Results of operations (excluding corporate overhead and interest)	$ 335.3	107.6	53.3	482.6	(256.0)	722.8
Nine Months Ended September 30, 2013						
Oil and gas sales and other revenues	$ 1,365.1	561.1	332.9	1,652.7	68.9	3,980.7
Lease operating expenses	204.8	135.3	169.0	248.9	89.5	847.5
Severance and ad valorem taxes	50.3	3.8	3.7	–	–	57.8
Depreciation, depletion and amortization	424.3	248.5	40.5	414.7	3.6	1,131.6
Accretion of asset retirement obligations	10.0	4.4	7.8	10.6	3.6	36.4
Impairment of properties	–	21.6	–	–	–	21.6

Exploration expenses						
Dry holes	0.6	32.0	–	1.2	126.7	160.5
Geological and geophysical	16.4	(0.5)	–	1.5	71.1	88.5
Other	6.1	0.8	–	–	35.9	42.8
	23.1	32.3	–	2.7	233.7	291.8
Undeveloped lease amortization	23.2	15.8	–	–	14.3	53.3
Total exploration expenses	46.3	48.1	–	2.7	248.0	345.1
Selling and general expenses	57.1	17.0	0.7	2.0	44.1	120.9
Results of operations before taxes	572.3	82.4	111.2	973.8	(319.9)	1,419.8
Income tax provisions	204.3	22.2	29.1	371.3	6.6	633.5
Results of operations (excluding corporate overhead and interest)	$ 368.0	60.2	82.1	602.5	(326.5)	786.3

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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 a net cost of $40.4 million in the three months ended September 30, 2014 compared to a net benefit of $0.8 million in the same 2013 quarter. Net costs in the 2014 quarter were $41.2 million above the prior-year quarter due to unfavorable impacts from foreign currency exchange and higher net interest expense. Net after-tax gains of $3.1 million occurred in 2014 on transactions denominated in foreign currencies, while the 2013 quarter had net after-tax gains of $45.8 million. The increase in net interest expense of $9.1 million was mostly associated with lower financing costs being allocated to development projects in 2014, but also due to higher borrowing levels in the current year. Administrative expenses were lower in the 2014 quarter as the 2013 quarter had higher costs associated with U.S. retail marketing operations that were distributed to shareholders on August 30, 2013.

For the first nine months of 2014, corporate activities reflected net costs of $139.8 million compared to net costs of $78.7 million a year ago. Nine-month corporate costs in 2014 were unfavorable to 2013 by $61.1 million mostly related to higher interest expense and unfavorable foreign exchange impacts. Net interest expense was higher in 2014 compared to 2013 by $33.1 million due to larger average borrowings and lower levels of finance costs allocated to development projects in the current year. Total after-tax losses associated with foreign currency transactions were $1.0 million in the 2014 period compared to after-tax gains of $57.8 million in the first nine months of 2013. Administrative expenses in 2014 were below 2013 levels as the prior period had higher expenses associated with U.S. retail marketing operations that were distributed to shareholders in 2013.

Discontinued Operations

The Company has presented a number of businesses as discontinued operations in its consolidated financial statements. These businesses included:

•U.K. refining and marketing operations. The Company completed the sale of the U.K. retail marketing business on September 30, 2014. The Milford Haven, Wales, oil refinery and terminal assets were held for sale at the quarter end. The Company ceased processing crude oil throughputs at the Milford Haven refinery in May 2014 due to weak operating margins. Larger losses incurred by this business in the 2014 third quarter compared to the prior year were attributable to certain ongoing refining expenses which were not partially covered by crack spreads associated with processing crude oil following the shut down in May. Although Murphy had previously signed an agreement to sell the Milford Haven, Wales, refinery and terminal assets, the transaction could not be completed by the October 31, 2014 deadline. The refinery is currently in a period of shut-down and will be decommissioned and operated as a petroleum storage and distribution terminal while the Company seeks a buyer for the terminal facility and three inland terminals. Although the Company realized an after-tax gain of $98.7 million on the sale of the retail marketing business, the anticipated loss on the Milford Haven refinery mostly offset the realized retail marketing gain.

•U.S. retail marketing company, now known as Murphy USA Inc., spun-off to shareholders on August 30, 2013. Results of operations for this business were included in the Company's 2013 financial statements through the spin-off date.

•U.K. oil and gas assets sold through a series of transactions in the first half of 2013. The Company's 2013 financial statements included both the results of operations through the respective dates the assets were sold and the cumulative gain realized upon sale. The nine-month period ended September 30, 2013 included an after-tax gain of $216.2 million from the sale of these properties.

The after-tax results of these operations for the three-month and nine-month periods ended September 30, 2014 and 2013 are reflected in the following table.

		Three Months Ended September 30,		Nine Months Ended September 30,	
(Millions of dollars)		2014	2013	2014	2013
U.K. refining and marketing	$	(25.4)	(12.9)	(52.4)	(22.7)
U.S. refining and marketing		–	33.0	–	140.3
U.K. exploration and production		0.1	(0.3)	(0.2)	222.8
Income (loss) from discontinued operations	$	(25.3)	19.8	(52.6)	340.4

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

Results of Operations (Contd.)

Discontinued Operations (Contd.)

Selected operating statistics for the U.K. refining and marketing operations for the three-month and nine-month periods ended September 30, 2014 and 2013 follow.

	Three Months Ended September 30,		Nine Months Ended September 30,	
(Millions of dollars)	2014	2013	2014	2013
U.K. refining and marketing – unit margins per barrel of petroleum products sold	$ (6.48)	(0.66)	$ (1.95)	(0.34)
U.K. petroleum products sold – barrels per day	34,337	137,526	77,728	131,177
Gasoline	8,594	50,505	26,399	48,061
Kerosine	4,299	19,499	9,676	16,674
Diesel and home heating oils	21,407	50,034	30,298	47,752
Residuals	2	12,062	5,784	13,874
LPG and other	35	5,426	5,571	4,816
U.K. refinery inputs – barrels per day	–	129,767	56,881	126,303
Milford Haven, Wales – crude oil	–	126,761	54,864	123,218
– other feedstocks	–	3,006	2,017	3,085
U.K. refinery yields – barrels per day	–	129,767	56,881	124,542
Gasoline	–	48,115	21,330	43,875
Kerosine	–	17,966	7,787	16,266
Diesel and home heating oils	–	47,729	18,875	44,637
Residuals	–	12,138	5,333	13,731
LPG and other	–	646	1,969	2,952
Fuel and loss	–	3,173	1,587	3,081

Financial Condition

Net cash provided by operating activities was $2,354.0 million for the first nine months of 2014 compared to $2,678.5 million during the same period in 2013. Excluding discontinued operations, cash flow from continuing operations increased from $2,218.0 million in the first nine months of 2013 to $2,334.3 million in the same 2014 period. Changes in operating working capital other than cash and cash equivalents from continuing operations generated cash of $6.9 million during the first nine months of 2014, but these working capital changes required cash of $24.5 million in 2013. Other significant sources of cash included $587.3 million in the 2014 period and $496.4 million in 2013 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. The Company borrowed $1.05 billion in the 2014 nine-months to fund capital development activities and repurchase Company stock. Prior to the spin-off of Murphy USA Inc. (MUSA), this former subsidiary borrowed $650.0 million primarily through the debt market. On the separation date of August 30, 2013, MUSA paid a $650.0 million cash dividend to Murphy Oil Corporation, which primarily used this dividend to repay a portion of its outstanding debt.

The most significant use of cash in both years was for property additions and dry holes for continuing operations, which including amounts expensed, were $2,806.7 million and $2,695.5 million in the nine-month periods ended September 30, 2014 and 2013, respectively. Total cash dividends to shareholders amounted to $174.2 million in 2014 and $177.8 million in 2013. The Company increased its quarterly dividends on outstanding Common stock from 0.3125 per share in the second quarter 2014 to $0.35 per share beginning in the third quarter of 2014. The Company expended $375.0 million to acquire 6,088,975 shares of Common stock through share repurchases during the first nine months of 2014. In the first nine months of 2013, the Company spent $250.0 million to repurchase Common shares. Also, the purchase of Canadian government securities with maturity dates greater than 90 days at acquisition used cash of $672.7 million in the 2014 period and $670.6 million in the 2013 period.

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

Financial Condition (Contd.)

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

	Nine Months Ended September 30,	
(Millions of dollars)	2014	2013
Capital Expenditures – Continuing operations		
Exploration and production	$ 2,828.0	2,933.2
Corporate	5.6	19.6
Total capital expenditures	$ 2,833.6	2,952.8

The reduction in capital expenditures in the exploration and production business in 2014 was primarily attributable to lower levels of development spend in Malaysia, but this was somewhat offset by more drilling and development activities in the Eagle Ford Shale area and higher spend on exploration drilling and lease acquisitions in the Gulf of Mexico in the current year. Capital expenditures exclude production equipment leased at the Kakap field, offshore Malaysia, during 2013.

A reconciliation of property additions and dry hole costs in the Consolidated Statements of Cash Flows to total capital expenditures for continuing operations follows.

	Nine Months Ended September 30,	
(Millions of dollars)	2014	2013
Property additions and dry hole costs per cash flow statements	$ 2,806.7	2,695.5
Geophysical and other exploration expenses	131.4	131.3
Capital expenditure accrual changes	(104.5)	126.0
Total capital expenditures	$ 2,833.6	2,952.8

Working capital (total current assets less total current liabilities) at September 30, 2014 was $666.9 million, $382.3 million more than December 31, 2013, with the increase attributable to amounts receivable from sale of the

U.K. retail marketing business on September 30, 2014, plus higher invested cash balances held by the Company's Canadian operations and lower amounts payable for income taxes and other operating activities at the quarter-end balance sheet date.

At September 30, 2014, long-term debt of $3,986.3 million had increased by $1.05 billion compared to December 31, 2013. A summary of capital employed at September 30, 2014 and December 31, 2013 follows.

	September 30, 2014		December 31, 2013	
(Millions of dollars)	Amount	%	Amount	%
Capital employed				
Long-term debt	$ 3,986.3	32.2 %	$ 2,936.6	25.5 %
Stockholders' equity	8,402.5	67.8	8,595.7	74.5
Total capital employed	$ 12,388.8	100.0 %	$ 11,532.3	100.0 %

The Company's ratio of earnings to fixed charges was 8.1 to 1 for the nine-month period ended September 30, 2014.

Cash and invested cash are maintained in several operating locations outside the United States. At September 30, 2014, cash, cash equivalents and cash temporarily invested in Canadian government securities held outside the U.S. included U.S. dollar equivalents of approximately $541 million in Canada and $452 million in Malaysia. In addition $198 million of cash was held in the United Kingdom, but this amount was reflected in current Assets Held for Sale on the Company's consolidated balance sheet at September 30, 2014. 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

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. For companies to whom the rule applies, the first annual report for conflict minerals was required to be filed no later than June 2, 2014 for the calendar year of 2013. Based on its assessment, the Company has determined that the rule does not currently apply to it and, therefore, it did not file an annual "conflict minerals" report for 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 D.C. Court found that the SEC misread the Act to mandate public disclosure of reports and that the denial of exemptions in the case of countries that prohibit public disclosures was improper. The Court remanded the matter to the SEC, which has indicated that it will restart the rulemaking process. The SEC has targeted the first quarter of 2015 for issuance of new rules on this matter. The Company cannot predict how the SEC will alter its rules based on the Court's findings.

In August 2014, the Financial Accounting Standards Board (FASB) issued an Accounting Standards Update (ASU), requiring, when applicable, disclosures regarding uncertainties about an entity's ability to continue as a going concern. During the preparation of quarterly and annual financial statements, management should evaluate whether conditions or events exist that raise substantial doubt about the entity's ability to continue as a going concern within one year after the date the financial statements are issued. If this evaluation indicates that it is probable that an entity will be unable to meet its obligations when they become due within one year of the financial statement issuance date, management must evaluate whether its mitigation plans will alleviate the substantial doubt of continuing as a going concern. If substantial doubt exists, regardless of whether the mitigation plan alleviates the concern, additional disclosures are required in the financial statements addressing the conditions or events that raise substantial doubt, management's evaluation of the significance of those conditions or events, and management's mitigation plans. This new guidance will become effective for the Company for all reporting periods beginning in 2016. Early application is permitted. Company management currently does not expect that this new guidance will have a significant effect on its consolidated financial statements when adopted.

In May 2014, FASB issued an ASU addressing recognition of revenue from contracts with customers. When adopted, this guidance will supersede current revenue recognition rules currently followed by the Company. The core principle of the new ASU is that an entity should recognize revenue to depict the transfer of promised goods or services to customers that reflects the consideration to which the entity expects to be entitled in exchange for those goods or services. The ASU provides five steps for an entity to apply in recognizing revenue, including: (1) identify the customer contract; (2) identify the contractual performance obligations; (3) determine the transaction price; (4) allocate the transaction price to the contractual performance obligations; and (5) recognize revenue when the performance obligation is satisfied. The new ASU also requires additional disclosures regarding significant contracts with customers. The new ASU will be effective for the Company on January 1, 2017, and early adoption is not permitted. For transition purposes, the new ASU permits either (a) a retrospective application to all years presented, or (b) an alternative transition method whereby the new guidance is only applied to contracts not completed at the date of initial application. The vast majority of the Company's revenue is recognized when oil and natural gas produced by the Company is delivered and legal ownership of these products has transferred to the purchaser. Based on the Company's present understanding, the accounting for oil and gas sales revenue is not expected to be significantly altered by the new ASU. The Company has not yet selected which transition method it will use.

In April 2014, the FASB issued an ASU that will change the requirements for reporting discontinued operations after its adoption. Under the new guidance, only disposals of components of an entity that represent a strategic shift that has or will have a major effect on an entity's operations and financial results will be reported as discontinued operations in the financial statements. Under prior guidance, a component of an entity that is a reportable segment, an operating segment, a reporting unit, a subsidiary, or an asset group that has been or will be eliminated from ongoing operations and for which the Company will not have any significant continuing involvement with the component after the disposal was generally reported as discontinued operations. The FASB anticipates that fewer component disposals will be reported as discontinued operations under the new guidance. The new guidance also requires expanded disclosures about discontinued operations. The new guidance will be effective for the Company beginning in 2015. The new guidance is not to be applied to a component that is classified as held for sale before the effective date of the guidance.

Outlook

Average worldwide crude oil prices in October and early November 2014 fell significantly compared to the average price during the third quarter of 2014. The price reduction appears to be based on rising crude oil inventories and concerns regarding future petroleum demand in the face of a weakening economic outlook. North American natural gas prices in October 2014 have also weakened slightly compared to those experienced in the third quarter due to unseasonably warm weather in the northern U.S. The Company expects its total oil and natural gas production to average 250,000 barrels of oil equivalent per day in the fourth quarter 2014. The Company currently anticipates total capital expenditures for the full year 2014 to be approximately $3.8 billion.

The Company primarily funds its capital program using operating cash flow, but supplements funding where necessary using borrowings under available credit facilities. Weaker oil and/or natural gas prices normally lead to lower cash flow generated from operations, which could lead to higher than anticipated borrowings in order to maintain funding of the Company's ongoing development projects. A period of low crude oil and/or gas prices could also cause the Company to reduce its capital spending program. Additionally, weaker oil and/or natural gas prices could lead to impairment of certain investments in oil and natural gas properties in a future period.

The Company has continued to carry out its announced plan to exit the U.K. refining and marketing business. The Company completed the sale of the U.K. marketing business on September 30, 2014. The Company had previously signed an agreement to sell the Milford Haven, Wales, refinery and terminal assets, but was unable to complete the transaction by the October 31, 2014 deadline. Due to the inability to complete the refinery sale, borrowings under credit facilities at the end of 2014 could be at a higher level than if the sale had been successfully completed and the available funds repatriated to the U.S. during 2014. The ultimate completion of the process to exit this U.K. business could lead to future financial accounting losses for the Company.

The Company has entered into an agreement to sell 30% of its working interest in most of its oil and gas properties in Malaysia. The sale price of $2.0 billion is subject to normal closing costs and adjustments. The sale is expected to close in two phases, with 20% being completed in December 2014 and 10% being completed in the first quarter 2015.

Through October 31, 2014, the Company has entered into derivative or forward fixed-price delivery contracts to manage risk associated with certain future oil and natural gas sales prices as follows:

Commodities	Contract or Location	Dates	Average Volumes per Day	Average Prices
U.S. Oil	West Texas Intermediate	Oct. – Dec. 2014	22,000 bbls/d	$93.26 per bbl.
Canadian Natural Gas	TCPL–NOVA System	Oct. – Dec. 2014	110 mmcf/d	Cdn$4.04 per mcf
		Jan. – Dec. 2015	65 mmcf/d	Cdn$4.13 per mcf
		Jan. – Dec. 2016	10 mmcf/d	Cdn$4.13 per mcf

Commodities	Contract	Dates	Average Volumes per Day	Average Netback Prices
Canadian Heavy Oil	Seal Blend	Oct. – Dec. 2014	4,000 bbls/d	$53.63 per bbl.*

* Represents average netback prices to the Company.

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

Forward-Looking Statements

This Form 10-Q contains forward-looking statements as defined in the Private Securities Litigation Reform Act of 1995. These statements, which express management's current views concerning future events or results, are subject to inherent risks and uncertainties. Factors that could cause actual results to differ materially from those expressed or implied in our forward-looking statements include, but are not limited to, the volatility and level of crude oil and natural gas prices, the level and success rate of our exploration programs, our ability to maintain production rates and replace reserves, customer demand for our products, adverse foreign exchange movements, political and regulatory instability, and uncontrollable natural hazards. Factors that could cause the sale of the Company's remaining U.K. downstream businesses, as discussed in this Form 10-Q, not to occur include, but are not limited to, a failure to obtain necessary regulatory approvals, a deterioration in the business or prospects of Murphy or its U.K. downstream operations, adverse developments in Murphy or its U.K. downstream operation's markets, adverse developments in the U.S. or global capital markets, credit markets or economies generally, and a failure to execute a sale of these U.K. operations on acceptable terms. For further discussion of risk factors, see Murphy's 2013 Annual Report on Form 10-K on file with the U.S. Securities and Exchange Commission and page 35 of this Form 10-Q report. Murphy undertakes no duty to publicly update or revise any forward-looking statements.

ITEM 3. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

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

There were commodity derivative contracts in place at September 30, 2014 covering certain future U.S. crude oil sales volumes in 2014. 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 $18.3 million, while a 10% decrease would have increased the recorded net asset by a similar amount.

There were derivative foreign exchange contracts in place at September 30, 2014 to hedge the value of the U.S. dollar against the Canadian dollar during October 2014. A 10% strengthening of the U.S. dollar against the Canadian dollar would have increased the recorded net liability associated with these contracts by approximately $1.3 million, while a 10% weakening of the U.S. dollar would have reduced the recorded net liability by approximately $1.6 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 September 30, 2014 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

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 its 2013 Form 10-K filed on February 28, 2014. A risk factor not previously disclosed in its 2013 Form 10-K report is included below.

Hydraulic fracturing exposes the Company to operational and regulatory risks.

The Company uses a technique known as hydraulic fracturing whereby water, sand and other chemicals are injected into deep oil and gas bearing reservoirs. This process creates fractures in the rock formation within the reservoir which enables oil and natural gas to migrate to the wellbore. The Company primarily uses this technique in the Eagle Ford Shale in South Texas and in Western Canada. Hydraulic fracturing operations subject the Company to operational risks inherent in the drilling and production of oil and natural gas, including relating to underground migration or surface spillage due to releases of oil, natural gas, formation water or well fluids, as well as any related surface or ground water contamination, including from petroleum constituents or hydraulic fracturing chemical additives. Ineffective containment of surface spillage and surface or ground water contamination resulting from hydraulic fracturing operations, including from petroleum constituents or hydraulic fracturing chemical additives, could result in environmental pollution, remediation expenses and third party claims alleging damages, which could adversely affect the Company's financial condition and results of operations. In addition, hydraulic fracturing requires significant quantities of water. Any diminished access to water for use in the process could curtail the Company's operations or otherwise result in operational delays or increased costs.

Hydraulic fracturing is generally regulated by the states, although certain hydraulic fracturing activities are also subject to existing and proposed federal regulations, including pursuant to the Safe Drinking Water Act and the Clean Air Act. In June 2011, the State of Texas adopted a law requiring public disclosure of information regarding components used in the hydraulic fracturing process. Similar disclosure requirements have also been implemented or proposed in other states and by the United States. The Canadian provinces of British Columbia and Alberta have also issued regulations related to hydraulic fracturing activities under their jurisdictions. It is possible that these and other jurisdictions may adopt further laws or regulations which could render the process less effective, increase costs or otherwise prohibit hydraulic fracturing activities in certain locations. If any such action is taken in the future, the Company's production levels could be adversely affected or its costs of drilling and completion could be increased.

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	
July 1, 2014 to July 31, 2014	–	$ –		–		$ –	
August 1, 2014 to August 31, 2014	97,486	–	1	97,486	1	500,000,000	2
September 1, 2014 to September 30, 2014	–	–		–		500,000,000	
Total July 1, 2014 to September 30, 2014	97,486	–		97,486		500,000,000	

1On May 20, 2014, the Company announced that it had entered into a $125 million variable term, capped accelerated share repurchase agreement (ASR) with a major financial institution. The total aggregate number of shares repurchased pursuant to this 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 ASR, subject to a minimum number of shares. In May, the Company received the minimum number of shares under the transaction, which totaled 1,850,037 shares. The ASR was completed in August 2014 and the Company received an additional 97,486 shares upon completion of the ASR. This brought the total number of shares acquired under this ASR transaction to 1,947,523, with the average purchase price equal to $64.18 per share.

2On August 6, 2014, the Company announced that its Board of Directors had approved a share buyback program of up to $500 million of the Company's shares of Common stock over the next year. As of the date of the filing of this Form 10-Q report, the Company has not repurchased any of its shares under this authorized share buyback program.

ITEM 6. EXHIBITS

The Exhibit Index on page 38 of this Form 10-Q report lists the exhibits that are hereby filed or incorporated by reference.

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)

November 5, 2014

(Date)

EXHIBIT INDEX

Exhibit No.	
2.1*	Purchase and Sale Contract for Malaysia Assets
12	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

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

*Portions of this document have been omitted and filed separately with the Commission pursuant to

a confidential treatment request under 17 C.F.R. 240.24b-2.