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

FORM 10-Q

(Mark One)

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

For the quarterly period ended September 30, 2013

or

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

Commission File Number: 1-9743

eog resources

EOG RESOURCES, INC.

(Exact name of registrant as specified in its charter)

Delaware	**47-0684736**
(State or other jurisdiction of incorporation or organization)	(I.R.S. Employer Identification No.)

1111 Bagby, Sky Lobby 2, Houston, Texas 77002
(Address of principal executive offices) (Zip Code)

713-651-7000
(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 ☒

Indicate the number of shares outstanding of each of the registrant's classes of common stock, as of the latest practicable date.

Title of each class	Number of shares
Common Stock, par value $0.01 per share	272,974,701 (as of October 30, 2013)

EOG RESOURCES, INC.

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PART I. FINANCIAL INFORMATION

ITEM 1. FINANCIAL STATEMENTS

EOG RESOURCES, INC.
CONSOLIDATED STATEMENTS OF INCOME AND COMPREHENSIVE INCOME
(In Thousands, Except Per Share Data)
(Unaudited)

	Three Months Ended September 30, 2013	Three Months Ended September 30, 2012	Nine Months Ended September 30, 2013	Nine Months Ended September 30, 2012
Net Operating Revenues				
Crude Oil and Condensate	$ 2,337,742	$ 1,512,168	$ 6,132,574	$ 4,198,753
Natural Gas Liquids	208,190	170,351	556,176	518,684
Natural Gas	396,123	426,728	1,269,604	1,153,433
(Losses) Gains on Mark-to-Market Commodity Derivative Contracts	(293,387)	4,671	(206,853)	327,328
Gathering, Processing and Marketing	872,699	764,385	2,755,069	2,193,290
Gains on Asset Dispositions, Net	8,183	67,376	185,569	248,134
Other, Net	11,846	9,176	45,956	31,203
Total	3,541,396	2,954,855	10,738,095	8,670,825
Operating Expenses				
Lease and Well	299,169	253,452	817,057	765,703
Transportation Costs	219,790	164,407	628,538	431,642
Gathering and Processing Costs	31,121	26,223	81,522	72,403
Exploration Costs	39,429	45,953	130,968	136,909
Dry Hole Costs	19,548	1,924	59,260	13,005
Impairments	85,917	62,875	177,432	250,239
Marketing Costs	876,761	755,457	2,746,900	2,155,043
Depreciation, Depletion and Amortization	928,800	825,851	2,685,719	2,383,359
General and Administrative	98,654	92,870	257,246	244,866
Taxes Other Than Income	172,438	120,096	458,566	359,798
Total	2,771,627	2,349,108	8,043,208	6,812,967
Operating Income	769,769	605,747	2,694,887	1,857,858
Other Income, Net	11,168	7,596	5,867	22,902
Income Before Interest Expense and Income Taxes	780,937	613,343	2,700,754	1,880,760
Interest Expense, Net	59,382	53,154	182,950	154,198
Income Before Income Taxes	721,555	560,189	2,517,804	1,726,562
Income Tax Provision	259,057	204,698	900,889	651,284
Net Income	**$ 462,498**	**$ 355,491**	**$ 1,616,915**	**$ 1,075,278**
Net Income Per Share				
Basic	$ 1.71	$ 1.33	$ 5.99	$ 4.03
Diluted	$ 1.69	$ 1.31	$ 5.93	$ 3.98
Dividends Declared per Common Share	$ 0.1875	$ 0.17	$ 0.5625	$ 0.51
Average Number of Common Shares				
Basic	270,471	267,941	269,934	267,136
Diluted	273,576	270,982	272,856	270,328
Comprehensive Income				
Net Income	$ 462,498	$ 355,491	$ 1,616,915	$ 1,075,278
Other Comprehensive Income (Loss)				
Foreign Currency Translation Adjustments	15,106	50,426	(18,472)	48,262
Foreign Currency Swap Transaction	1,459	1,708	2,498	2,338
Income Tax Related to Foreign Currency Swap Transaction	-	(646)	-	(597)
Interest Rate Swap Transaction	678	(318)	1,999	(682)
Income Tax Related to Interest Rate Swap Transaction	(244)	114	(719)	245
Other	27	29	82	87
Other Comprehensive Income (Loss)	17,026	51,313	(14,612)	49,653
Comprehensive Income	**$ 479,524**	**$ 406,804**	**$ 1,602,303**	**$ 1,124,931**

The accompanying notes are an integral part of these consolidated financial statements.

EOG RESOURCES, INC.
CONSOLIDATED BALANCE SHEETS
(In Thousands, Except Share Data)
(Unaudited)

	September 30, 2013	December 31, 2012
ASSETS		
Current Assets		
Cash and Cash Equivalents	$ 1,318,817	$ 876,435
Accounts Receivable, Net	1,849,517	1,656,618
Inventories	566,004	683,187
Assets from Price Risk Management Activities	44,484	166,135
Income Taxes Receivable	42,296	29,163
Deferred Income Taxes	127,658	-
Other	243,191	178,346
Total	4,191,967	3,589,884
Property, Plant and Equipment		
Oil and Gas Properties (Successful Efforts Method)	41,887,901	38,126,298
Other Property, Plant and Equipment	2,954,085	2,740,619
Total Property, Plant and Equipment	44,841,986	40,866,917
Less: Accumulated Depreciation, Depletion and Amortization	(19,242,795)	(17,529,236)
Total Property, Plant and Equipment, Net	25,599,191	23,337,681
Other Assets	356,112	409,013
Total Assets	**$ 30,147,270**	**$ 27,336,578**
LIABILITIES AND STOCKHOLDERS' EQUITY		
Current Liabilities		
Accounts Payable	$ 2,247,714	$ 2,078,948
Accrued Taxes Payable	200,477	162,083
Dividends Payable	50,753	45,802
Liabilities from Price Risk Management Activities	174,648	7,617
Deferred Income Taxes	-	22,838
Current Portion of Long-Term Debt	406,579	406,579
Other	267,162	200,191
Total	3,347,333	2,924,058
Long-Term Debt	5,906,494	5,905,602
Other Liabilities	846,780	894,758
Deferred Income Taxes	5,185,083	4,327,396
Commitments and Contingencies (Note 8)		
Stockholders' Equity		
Common Stock, $0.01 Par, 640,000,000 Shares Authorized and 273,061,895 Shares Issued at September 30, 2013 and 271,958,495 Shares Issued at December 31, 2012	202,731	202,720
Additional Paid in Capital	2,614,898	2,500,340
Accumulated Other Comprehensive Income	425,283	439,895
Retained Earnings	11,639,302	10,175,631
Common Stock Held in Treasury, 142,467 Shares at September 30, 2013 and 326,264 Shares at December 31, 2012	(20,634)	(33,822)
Total Stockholders' Equity	14,861,580	13,284,764
Total Liabilities and Stockholders' Equity	**$ 30,147,270**	**$ 27,336,578**

The accompanying notes are an integral part of these consolidated financial statements.

EOG RESOURCES, INC.
CONSOLIDATED STATEMENTS OF CASH FLOWS
(In Thousands)
(Unaudited)

	Nine Months Ended September 30, 2013	Nine Months Ended September 30, 2012
Cash Flows from Operating Activities		
Reconciliation of Net Income to Net Cash Provided by Operating Activities:		
Net Income	$ 1,616,915	$ 1,075,278
Items Not Requiring (Providing) Cash		
Depreciation, Depletion and Amortization	2,685,719	2,383,359
Impairments	177,432	250,239
Stock-Based Compensation Expenses	103,171	101,337
Deferred Income Taxes	657,686	385,878
Gains on Asset Dispositions, Net	(185,569)	(248,134)
Other, Net	460	(10,266)
Dry Hole Costs	59,260	13,005
Mark-to-Market Commodity Derivative Contracts		
Total Losses (Gains)	206,853	(327,328)
Realized Gains	115,323	555,946
Excess Tax Benefits from Stock-Based Compensation	(50,230)	(49,426)
Other, Net	16,222	12,675
Changes in Components of Working Capital and Other Assets and Liabilities		
Accounts Receivable	(213,746)	(112,174)
Inventories	61,147	(154,766)
Accounts Payable	145,199	83,682
Accrued Taxes Payable	73,197	42,791
Other Assets	(78,799)	(120,085)
Other Liabilities	10,889	39,871
Changes in Components of Working Capital Associated with Investing and Financing Activities	(72,945)	87,708
Net Cash Provided by Operating Activities	5,328,184	4,009,590
Investing Cash Flows		
Additions to Oil and Gas Properties	(5,084,335)	(5,326,884)
Additions to Other Property, Plant and Equipment	(271,136)	(477,351)
Proceeds from Sales of Assets	587,273	1,213,550
Changes in Restricted Cash	(68,061)	-
Changes in Components of Working Capital Associated with Investing Activities	72,916	(87,654)
Net Cash Used in Investing Activities	(4,763,343)	(4,678,339)
Financing Cash Flows		
Long-Term Debt Borrowings	-	1,234,138
Dividends Paid	(147,731)	(134,412)
Excess Tax Benefits from Stock-Based Compensation	50,230	49,426
Treasury Stock Purchased	(55,562)	(44,799)
Proceeds from Stock Options Exercised and Employee Stock Purchase Plan	30,080	59,714
Debt Issuance Costs	-	(1,771)
Repayment of Capital Lease Obligation	(4,318)	(1,407)
Other, Net	29	(54)
Net Cash (Used in) Provided by Financing Activities	(127,272)	1,160,835
Effect of Exchange Rate Changes on Cash	4,813	4,811
Increase in Cash and Cash Equivalents	442,382	496,897
Cash and Cash Equivalents at Beginning of Period	876,435	615,726
Cash and Cash Equivalents at End of Period	**$ 1,318,817**	**$ 1,112,623**

The accompanying notes are an integral part of these consolidated financial statements.

1. Summary of Significant Accounting Policies

General. The consolidated financial statements of EOG Resources, Inc., together with its subsidiaries (collectively, EOG), included herein have been prepared by management without audit pursuant to the rules and regulations of the United States Securities and Exchange Commission (SEC). Accordingly, they reflect all normal recurring adjustments which are, in the opinion of management, necessary for a fair presentation of the financial results for the interim periods presented. Certain information and notes normally included in financial statements prepared in accordance with accounting principles generally accepted in the United States of America (U.S. GAAP) have been condensed or omitted pursuant to such rules and regulations. However, management believes that the disclosures included either on the face of the financial statements or in these notes are sufficient to make the interim information presented not misleading. These consolidated financial statements should be read in conjunction with the consolidated financial statements and the notes thereto included in EOG's Annual Report on Form 10-K for the year ended December 31, 2012, filed on February 22, 2013 (EOG's 2012 Annual Report).

The preparation of financial statements in conformity with U.S. GAAP requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenues and expenses during the reporting period. Actual results could differ from those estimates. The operating results for the three and nine months ended September 30, 2013 are not necessarily indicative of the results to be expected for the full year.

Recently Issued Accounting Standards. In February 2013, the Financial Accounting Standards Board (FASB) issued Accounting Standards Update (ASU) 2013-02 "Reporting of Amounts Reclassified Out of Accumulated Other Comprehensive Income" (ASU 2013-02). ASU 2013-02 amends ASU 2011-05 and requires that entities disclose additional information about amounts reclassified out of Accumulated Other Comprehensive Income (AOCI) by component. Significant amounts reclassified out of AOCI are required to be presented either on the face of the Consolidated Statements of Income and Comprehensive Income or in the notes to the financial statements. The requirements of ASU 2013-02 are effective for fiscal years and interim periods in those years beginning after December 15, 2012. EOG adopted the provisions of ASU 2013-02 effective January 1, 2013. The adoption did not have a material impact on EOG's financial statements. No significant amounts were reclassified out of AOCI during the three and nine months ended September 30, 2013 and 2012, respectively.

In July 2013, the FASB issued ASU 2013-11 "Presentation of an Unrecognized Tax Benefit when a Net Operating Loss Carryforward, a Similar Tax Loss, or a Tax Credit Carryforward Exists" (ASU 2013-11). ASU 2013-11 includes specific guidance on financial statement presentation of an unrecognized tax benefit when a net operating loss carryforward, a similar tax loss, or a tax credit carryforward exists. The requirements of ASU 2013-11 are effective for fiscal years and interim periods in those years beginning after December 15, 2013. Early adoption is permitted. EOG does not expect a material impact on its financial statements from the adoption of ASU 2013-11.

2. Stock-Based Compensation

As more fully discussed in Note 6 to the Consolidated Financial Statements included in EOG's 2012 Annual Report, EOG maintains various stock-based compensation plans. Stock-based compensation expense is included on the Consolidated Statements of Income and Comprehensive Income based upon the job function of the employees receiving the grants as follows (in millions):

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2013	2012	2013	2012
Lease and Well	$ 7.2	$ 9.9	$ 25.4	$ 26.4
Gathering and Processing Costs	0.3	0.3	0.9	0.8
Exploration Costs	6.7	7.4	20.6	20.3
General and Administrative	31.3	28.3	56.3	53.8
Total	$ 45.5	$ 45.9	$ 103.2	$ 101.3

At the 2013 Annual Meeting of Stockholders, EOG's stockholders approved the Amended and Restated EOG Resources, Inc. 2008 Omnibus Equity Compensation Plan (2008 Plan). As more fully discussed in the 2008 Plan document, the 2008 Plan, among other things, authorizes an additional 15,500,000 shares of EOG common stock for grant under the 2008 Plan and extends the expiration date of the 2008 Plan to May 2023.

The 2008 Plan provides for grants of stock options, stock-settled stock appreciation rights (SARs), restricted stock, restricted stock units, performance units, performance stock and other stock-based awards. At September 30, 2013, approximately 16.6 million common shares remained available for grant under the 2008 Plan. EOG's policy is to issue shares related to the 2008 Plan from either previously authorized unissued shares or treasury shares to the extent treasury shares are available.

Stock Options and Stock-Settled Stock Appreciation Rights and Employee Stock Purchase Plan. The fair value of stock option and SAR grants is estimated using the Hull-White II binomial option pricing model. The fair value of Employee Stock Purchase Plan (ESPP) grants is estimated using the Black-Scholes-Merton model. Stock-based compensation expense related to stock option, SAR and ESPP grants totaled $19.2 million and $16.5 million during the three months ended September 30, 2013 and 2012, respectively, and $40.0 million and $37.8 million during the nine months ended September 30, 2013 and 2012, respectively.

Weighted average fair values and valuation assumptions used to value stock option, SAR and ESPP grants during the nine-month periods ended September 30, 2013 and 2012 are as follows:

	Stock Options/SARs Nine Months Ended September 30,		ESPP Nine Months Ended September 30,	
	2013	2012	2013	2012
Weighted Average Fair Value of Grants	$ 54.68	$ 37.94	$ 30.13	$ 25.17
Expected Volatility	35.86 %	39.68%	29.89%	41.04%
Risk-Free Interest Rate	0.78 %	0.45%	0.11%	0.11%
Dividend Yield	0.40 %	0.60%	0.60%	0.60%
Expected Life	5.5 yrs	5.6 yrs	0.5 yrs	0.5 yrs

Expected volatility is based on an equal weighting of historical volatility and implied volatility from traded options in EOG's common stock. The risk-free interest rate is based upon United States Treasury yields in effect at the time of grant. The expected life is based upon historical experience and contractual terms of stock option, SAR and ESPP grants.

The following table sets forth stock option and SAR transactions for the nine-month periods ended September 30, 2013 and 2012 (stock options and SARs in thousands):

	Nine Months Ended September 30, 2013		Nine Months Ended September 30, 2012	
	Number of Stock Options/SARs	**Weighted Average Grant Price**	**Number of Stock Options/SARs**	**Weighted Average Grant Price**
Outstanding at January 1	6,219	$ 85.81	8,374	$ 70.01
Granted	1,117	167.32	1,223	111.91
Exercised (1)	(1,824)	69.03	(2,044)	53.52
Forfeited	(84)	96.76	(124)	89.95
Outstanding at September 30 (2)	5,428	$ 108.06	7,429	$ 81.11
Vested or Expected to Vest (3)	5,199	$ 107.26	7,184	$ 80.57
Exercisable at September 30 (4)	2,491	$ 88.05	4,315	$ 69.87

(1) The total intrinsic value of stock options/SARs exercised for the nine months ended September 30, 2013 and 2012 was $134.2 million and $110.8 million, respectively. The intrinsic value is based upon the difference between the market price of EOG's common stock on the date of exercise and the grant price of the stock options/SARs.

(2) The total intrinsic value of stock options/SARs outstanding at September 30, 2013 and 2012 was $332.3 million and $231.1 million, respectively. At September 30, 2013 and 2012, the weighted average remaining contractual life was 4.8 years and 4.1 years, respectively.

(3) The total intrinsic value of stock options/SARs vested or expected to vest at September 30, 2013 and 2012 was $322.5 million and $227.3 million, respectively. At September 30, 2013 and 2012, the weighted average remaining contractual life was 4.7 years and 4.0 years, respectively.

(4) The total intrinsic value of stock options/SARs exercisable at September 30, 2013 and 2012 was $202.4 million and $182.7 million, respectively. At September 30, 2013 and 2012, the weighted average remaining contractual life was 3.5 years and 2.7 years, respectively.

At September 30, 2013, unrecognized compensation expense related to non-vested stock option, SAR and ESPP grants totaled $115.5 million. This unrecognized expense will be amortized on a straight-line basis over a weighted average period of 2.9 years.

Restricted Stock and Restricted Stock Units. Employees may be granted restricted (non-vested) stock and/or restricted stock units without cost to them. Stock-based compensation expense related to restricted stock and restricted stock unit grants totaled $19.2 million and $23.1 million for the three months ended September 30, 2013 and 2012, respectively, and $55.5 million and $57.2 million for the nine months ended September 30, 2013 and 2012, respectively.

The following table sets forth restricted stock and restricted stock unit transactions for the nine-month periods ended September 30, 2013 and 2012 (shares and units in thousands):

	Nine Months Ended September 30, 2013		**Nine Months Ended September 30, 2012**	
	Number of Shares and Units	**Weighted Average Grant Date Fair Value**	**Number of Shares and Units**	**Weighted Average Grant Date Fair Value**
Outstanding at January 1	3,818	$ 91.06	4,240	$ 82.93
Granted	642	151.85	757	112.13
Released [(1)]	(617)	105.77	(977)	72.97
Forfeited	(80)	95.39	(106)	88.36
Outstanding at September 30 [(2)]	3,763	$ 98.93	3,914	$ 90.91

(1) The total intrinsic value of restricted stock and restricted stock units released for the nine months ended September 30, 2013 and 2012 was $89.2 million and $110.7 million, respectively. The intrinsic value is based upon the closing price of EOG's common stock on the date restricted stock and restricted stock units are released.

(2) The total intrinsic value of restricted stock and restricted stock units outstanding at September 30, 2013 and 2012 was $637.0 million and $438.6 million, respectively.

At September 30, 2013, unrecognized compensation expense related to restricted stock and restricted stock unit grants totaled $171.8 million. Such unrecognized expense will be amortized on a straight-line basis over a weighted average period of 2.7 years.

Performance Units and Performance Stock. EOG grants performance units and/or performance stock to its executive officers. The fair value of the performance units and performance stock is estimated using a Monte Carlo simulation. Stock-based compensation expense related to performance unit and performance stock grants totaled $7.1 million and $6.3 million for the three months ended September 30, 2013 and 2012, respectively, and $7.7 million and $6.3 million for the nine months ended September 30, 2013 and 2012, respectively.

Weighted average fair values and valuation assumptions used to value performance unit and performance stock grants during the nine-month periods ended September 30, 2013 and 2012 are as follows:

	Nine Months Ended September 30,	
	2013	**2012**
Weighted Average Fair Value of Grants	$ 200.68	$ 134.09
Expected Volatility	33.63%	36.39%
Risk-Free Interest Rate	0.79%	0.39%

Expected volatility is based on the term-matched historical volatility over the simulated term, which is calculated as the time between the grant date and the end of the performance period. The risk-free interest rate is based on a 3.26 year zero-coupon risk-free interest rate derived from the Treasury Constant Maturities yield curve on the grant date.

The following table sets forth performance unit and performance stock transactions for the nine-month periods ended September 30, 2013 and 2012 (shares and units in thousands):

	Nine Months Ended September 30, 2013		Nine Months Ended September 30, 2012	
	Number of Shares and Units	Weighted Average Grant Date Fair Value	Number of Shares and Units	Weighted Average Grant Date Fair Value
Outstanding at January 1	71	$ 134.09	-	$ -
Granted	60	200.68	71	134.09
Released	-	-	-	-
Forfeited	-	-	-	-
Outstanding at September 30 (1)	131	$ 164.36	71	$ 134.09

(1) The total intrinsic value of performance units and performance stock outstanding at September 30, 2013 and 2012 was $22.1 million and $8.0 million, respectively.

At September 30, 2013, unrecognized compensation expense related to performance unit and performance stock grants totaled $7.1 million. Such unrecognized expense will be amortized on a straight-line basis over a weighted average period of 2.7 years.

3. Net Income Per Share

The following table sets forth the computation of Net Income Per Share for the three-month and nine-month periods ended September 30, 2013 and 2012 (in thousands, except per share data):

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2013	2012	2013	2012
Numerator for Basic and Diluted Earnings Per Share -				
Net Income	$ 462,498	$ 355,491	$ 1,616,915	$ 1,075,278
Denominator for Basic Earnings Per Share -				
Weighted Average Shares	270,471	267,941	269,934	267,136
Potential Dilutive Common Shares -				
Stock Options/SARs	1,189	1,343	1,098	1,517
Restricted Stock/Units and Performance Units/Stock	1,916	1,698	1,824	1,675
Denominator for Diluted Earnings Per Share -				
Adjusted Diluted Weighted Average Shares	273,576	270,982	272,856	270,328
Net Income Per Share				
Basic	$ 1.71	$ 1.33	$ 5.99	$ 4.03
Diluted	$ 1.69	$ 1.31	$ 5.93	$ 3.98

The diluted earnings per share calculation excluded stock options and SARs that were anti-dilutive. Shares underlying the excluded stock options and SARs totaled 0.3 million and 0.5 million shares for the three months ended September 30, 2013 and 2012, respectively, and 0.1 million and 0.3 million shares for the nine months ended September 30, 2013 and 2012, respectively.

4. Supplemental Cash Flow Information

Net cash paid for interest and income taxes was as follows for the nine-month periods ended September 30, 2013 and 2012 (in thousands):

	Nine Months Ended September 30, 2013	Nine Months Ended September 30, 2012
Interest [(1)]	$ 172,808	$ 132,264
Income Taxes, Net of Refunds Received	$ 220,450	$ 257,046

(1) Net of capitalized interest of $34 million and $37 million for the nine months ended September 30, 2013 and 2012, respectively.

EOG's accrued capital expenditures at September 30, 2013 and 2012 were $743 million and $725 million, respectively.

5. Segment Information

Selected financial information by reportable segment is presented below for the three-month and nine-month periods ended September 30, 2013 and 2012 (in thousands):

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2013	2012	2013	2012
Net Operating Revenues				
United States	$ 3,337,008	$ 2,702,046	$ 9,981,084	$ 7,953,839
Canada	77,515	79,500	350,398	264,059
Trinidad	122,280	167,402	390,552	434,746
Other International [(1)]	4,593	5,907	16,061	18,181
Total	$ 3,541,396	$ 2,954,855	$ 10,738,095	$ 8,670,825
Operating Income (Loss)				
United States	$ 747,958	$ 545,982	$ 2,522,127	$ 1,711,860
Canada	(21,647)	(40,477)	29,683	(93,113)
Trinidad	61,087	114,709	213,875	284,869
Other International [(1)]	(17,629)	(14,467)	(70,798)	(45,758)
Total	769,769	605,747	2,694,887	1,857,858
Reconciling Items				
Other Income, Net	11,168	7,596	5,867	22,902
Interest Expense, Net	59,382	53,154	182,950	154,198
Income Before Income Taxes	$ 721,555	$ 560,189	$ 2,517,804	$ 1,726,562

(1) Other International primarily includes EOG's United Kingdom, China and Argentina operations.

Total assets by reportable segment are presented below at September 30, 2013 and December 31, 2012 (in thousands):

	At September 30, 2013	At December 31, 2012
Total Assets		
United States	$ 27,151,274	$ 24,523,072
Canada	982,639	1,202,031
Trinidad	989,262	1,012,727
Other International [1]	1,024,095	598,748
Total	$ 30,147,270	$ 27,336,578

(1) Other International primarily includes EOG's United Kingdom, China and Argentina operations.

6. Asset Retirement Obligations

The following table presents the reconciliation of the beginning and ending aggregate carrying amounts of short-term and long-term legal obligations associated with the retirement of property, plant and equipment for the nine-month periods ended September 30, 2013 and 2012 (in thousands):

	Nine Months Ended September 30,	
	2013	2012
Carrying Amount at Beginning of Period	$ 665,944	$ 587,084
Liabilities Incurred	48,556	47,320
Liabilities Settled [1]	(54,859)	(56,150)
Accretion	26,421	22,714
Revisions	27,252	12,709
Foreign Currency Translations	(5,898)	5,140
Carrying Amount at End of Period	$ 707,416	$ 618,817
Current Portion	$ 14,329	$ 27,615
Noncurrent Portion	$ 693,087	$ 591,202

(1) Includes settlements related to asset sales.

The current and noncurrent portions of EOG's asset retirement obligations are included in Current Liabilities - Other and Other Liabilities, respectively, on the Consolidated Balance Sheets.

7. Exploratory Well Costs

EOG's net changes in capitalized exploratory well costs for the nine-month period ended September 30, 2013 are presented below (in thousands):

	Nine Months Ended September 30, 2013
Balance at December 31, 2012	$ 49,116
Additions Pending the Determination of Proved Reserves	64,343
Reclassifications to Proved Properties	(49,742)
Costs Charged to Expense [1]	(31,006)
Foreign Currency Translations	(1,355)
Balance at September 30, 2013	$ 31,356

(1) Includes capitalized exploratory well costs charged to dry hole costs.

At September 30, 2013, all capitalized exploratory well costs had been capitalized for a period of less than one year.

8. Commitments and Contingencies

There are currently various suits and claims pending against EOG that have arisen in the ordinary course of EOG's business, including contract disputes, personal injury and property damage claims and title disputes. While the ultimate outcome and impact on EOG cannot be predicted, management believes that the resolution of these suits and claims will not, individually or in the aggregate, have a material adverse effect on EOG's consolidated financial position, results of operations or cash flow. EOG records reserves for contingencies when information available indicates that a loss is probable and the amount of the loss can be reasonably estimated.

9. Pension and Postretirement Benefits

EOG has defined contribution pension plans in place for most of its employees in the United States, Canada, Trinidad and the United Kingdom, and defined benefit pension plans covering certain of its employees in Canada and Trinidad. For the nine months ended September 30, 2013 and 2012, EOG's total costs recognized for these pension plans were $28.9 million and $27.1 million, respectively. EOG also has postretirement medical and dental plans in place for eligible employees in the United States and Trinidad, the costs of which are not material.

10. Long-Term Debt

Long-Term Debt. During the nine months ended September 30, 2013 and 2012, EOG utilized commercial paper, bearing market interest rates, for various corporate financing purposes. EOG had no outstanding borrowings from commercial paper issuances at September 30, 2013. The average of the borrowings outstanding under the commercial paper program was $23 million during the nine months ended September 30, 2013. The weighted average interest rate for commercial paper borrowings for the nine months ended September 30, 2013 was 0.30%. At September 30, 2013, $350 million principal amount of Floating Rate Senior Notes due 2014 (Floating Rate Notes) and $150 million principal amount of 4.75% Subsidiary Debt due 2014 (4.75% Subsidiary Debt) were classified as long-term debt based upon EOG's intent and ability to ultimately replace such amounts with other long-term debt. On October 1, 2013, EOG repaid, at maturity, the $400 million principal amount of its 6.125% Senior Notes.

EOG currently has a $2.0 billion unsecured Revolving Credit Agreement (Agreement) with domestic and foreign lenders. The Agreement matures on October 11, 2016 and includes an option for EOG to extend, on up to two occasions, the term for successive one-year periods, subject to, among certain other terms and conditions, the consent of the banks holding greater than 50% of the commitments then outstanding under the Agreement. At September 30, 2013, there were no borrowings or letters of credit outstanding under the Agreement. Advances under the Agreement accrue interest based, at EOG's option, on either the London InterBank Offered Rate (LIBOR) plus an applicable margin (Eurodollar rate), or the base rate (as defined in the Agreement) plus an applicable margin. At September 30, 2013, the Eurodollar rate and applicable base rate, had there been any amounts borrowed under the Agreement, would have been 1.05 % and 3.25 %, respectively.

Restricted Cash. In May 2013, the Canadian Alberta Energy Regulator (AER) made effective certain regulations affecting the Licensee Liability Rating program which requires well owners to post financial security for well abandonment obligations in amounts set forth by the AER. In order to comply with these requirements, EOG Resources Canada Inc. (EOGRC) established a 160 million Canadian dollar letter of credit facility (maturing May 29, 2018) with Royal Bank of Canada (RBC) as the lender. The letter of credit facility requires EOGRC to deposit cash, in an amount equal to all outstanding letters of credit under such facility, in a cash collateral account at RBC. At September 30, 2013, the balance in this account was 70 million Canadian dollars (68 million United States dollars).

11. Fair Value Measurements

As more fully discussed in Note 12 to the Consolidated Financial Statements included in EOG's 2012 Annual Report, certain of EOG's financial and nonfinancial assets and liabilities are reported at fair value on the Consolidated Balance Sheets. The following table provides fair value measurement information within the fair value hierarchy for certain of EOG's financial assets and liabilities carried at fair value on a recurring basis at September 30, 2013 and December 31, 2012 (in millions):

	Fair Value Measurements Using:			
	Quoted Prices in Active Markets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Total
At September 30, 2013				
Financial Assets:				
Natural Gas Options/Swaptions	$ -	$ 48	$ -	$ 48
Financial Liabilities:				
Crude Oil Swaps	$ -	$ 16	$ -	$ 16
Crude Oil Options/Swaptions	-	159	-	159
Foreign Currency Rate Swap	-	46	-	46
Interest Rate Swap	-	2	-	2
At December 31, 2012				
Financial Assets:				
Crude Oil Swaps	$ -	$ 65	$ -	$ 65
Crude Oil Options/Swaptions	-	36	-	36
Natural Gas Options/Swaptions	-	65	-	65
Financial Liabilities:				
Crude Oil Options/Swaptions	$ -	$ 8	$ -	$ 8
Natural Gas Options/Swaptions	-	13	-	13
Foreign Currency Rate Swap	-	55	-	55
Interest Rate Swap	-	4	-	4

The estimated fair value of crude oil and natural gas derivative contracts (including options/swaptions) and the interest rate swap contract was based upon forward commodity price and interest rate curves based on quoted market prices. The estimated fair value of the foreign currency rate swap was based upon forward currency rates. Commodity derivative contracts were valued by utilizing an independent third-party derivative valuation provider who uses various types of valuation models, as applicable.

The initial measurement of asset retirement obligations at fair value is calculated using discounted cash flow techniques and based on internal estimates of future retirement costs associated with property, plant and equipment. Significant Level 3 inputs used in the calculation of asset retirement obligations include plugging costs and reserve lives. A reconciliation of EOG's asset retirement obligations is presented in Note 6.

Proved oil and gas properties and other assets with a carrying amount of $247 million were written down to their fair value of $154 million, resulting in pretax impairment charges of $93 million for the nine months ended September 30, 2013. Included in the $93 million pretax impairment charges are $7 million of impairments of proved oil and gas properties for which EOG utilized an accepted offer from a third-party purchaser as the basis for determining fair value. Significant Level 3 assumptions associated with the calculation of discounted cash flows used in the impairment analysis include EOG's estimate of future crude oil and natural gas prices, production costs, development expenditures, anticipated production of proved reserves, appropriate risk-adjusted discount rates and other relevant data.

Fair Value of Debt. At both September 30, 2013 and December 31, 2012, EOG had outstanding $6,290 million aggregate principal amount of debt, which had estimated fair values of approximately $6,692 million and $7,032 million, respectively. The estimated fair value of debt was based upon quoted market prices and, where such prices were not available, other observable (Level 2) inputs regarding interest rates available to EOG at the end of each respective period.

12. Risk Management Activities

Commodity Price Risk. As more fully discussed in Note 11 to the Consolidated Financial Statements included in EOG's 2012 Annual Report, EOG engages in price risk management activities from time to time. These activities are intended to manage EOG's exposure to fluctuations in commodity prices for crude oil and natural gas. EOG utilizes financial commodity derivative instruments, primarily price swap, option, swaption, collar and basis swap contracts, as a means to manage this price risk. EOG has not designated any of its financial commodity derivative contracts as hedges and, accordingly, accounts for financial commodity derivative contracts using the mark-to-market accounting method. In addition to financial transactions, from time to time EOG is a party to various physical commodity contracts for the sale of hydrocarbons that cover varying periods of time and have varying pricing provisions. These physical commodity contracts qualify for the normal purchases and normal sales exception and, therefore, are not subject to hedge accounting or mark-to-market accounting. The financial impact of physical commodity contracts is included in revenues at the time of settlement, which in turn affects average realized hydrocarbon prices.

Commodity Derivative Contracts. EOG entered into additional crude oil derivative contracts as a result of counterparties exercising outstanding options on September 30, 2013. In addition, during September 2013, EOG settled certain crude oil derivative contracts covering notional volumes of 5,000 barrels per day (Bbld) for the period July 1, 2014 through December 31, 2014. Presented below is a comprehensive summary of EOG's crude oil derivative contracts at September 30, 2013, with notional volumes expressed in Bbld and prices expressed in dollars per barrel ($/Bbl).

Crude Oil Derivative Contracts			
	Volume (Bbld)		Weighted Average Price ($/Bbl)
2013 [(1)]			
January 2013 (closed)	101,000	$	99.29
February 1, 2013 through April 30, 2013 (closed)	109,000		99.17
May 1, 2013 through June 30, 2013 (closed)	101,000		99.29
July 2013 (closed)	111,000		98.25
August 1, 2013 through September 30, 2013 (closed)	126,000		98.80
October 1, 2013 through December 31, 2013	126,000		98.80
2014 [(2)]			
January 1, 2014 through March 31, 2014	103,000	$	96.48
April 1, 2014 through June 30, 2014	93,000	$	96.47

(1) EOG has entered into crude oil derivative contracts which give counterparties the option to extend certain current derivative contracts for an additional six-month period. Options covering a notional volume of 64,000 Bbld are exercisable on December 31, 2013. If the counterparties exercise all such options, the notional volume of EOG's existing crude oil derivative contracts will increase by 64,000 Bbld at an average price of $99.58 per barrel for each month during the period January 1, 2014 through June 30, 2014.

(2) EOG has entered into crude oil derivative contracts which give counterparties the option to extend certain current derivative contracts for additional six-month and nine-month periods. Options covering a notional volume of 10,000 Bbld are exercisable on or about March 31, 2014. If the counterparties exercise all such options, the notional volume of EOG's existing crude oil derivative contracts will increase by 10,000 Bbld at an average price of $96.60 per barrel for each month during the period April 1, 2014 through December 31, 2014. Options covering a notional volume of 93,000 Bbld are exercisable on or about June 30, 2014. If the counterparties exercise all such options, the notional volume of EOG's existing crude oil derivative contracts will increase by 93,000 Bbld at an average price of $96.47 per barrel for each month during the period July 1, 2014 through December 31, 2014. In addition, in connection with the crude oil derivative contracts settled in September 2013, counterparties retain the option to enter into derivative contracts on December 31, 2014. If the counterparties exercise all such options, the notional volume of EOG's existing crude oil derivative contracts will increase by 5,000 Bbld at an average price of $95.43 per barrel for each month during the period January 1, 2015 through June 30, 2015.

Presented below is a comprehensive summary of EOG's natural gas derivative contracts at September 30, 2013, with notional volumes expressed in million British thermal units (MMBtu) per day (MMBtud) and prices expressed in dollars per MMBtu ($/MMBtu).

Natural Gas Derivative Contracts		
	Volume (MMBtud)	Weighted Average Price ($/MMBtu)
2013 (1)		
January 1, 2013 through April 30, 2013 (closed)	150,000	$ 4.79
May 1, 2013 through October 31, 2013 (closed)	200,000	4.72
November 1, 2013 through December 31, 2013	150,000	4.79
2014 (2)		
January 1, 2014 through December 31, 2014	170,000	$ 4.54

(1) EOG has entered into natural gas derivative contracts which give counterparties the option of entering into derivative contracts at future dates. Such options are exercisable monthly up until the settlement date of each monthly contract. For the period November 1, 2013 through December 31, 2013, if the counterparties exercise all such options, the notional volume of EOG's existing natural gas derivative contracts will increase by 150,000 MMBtud at an average price of $4.79 per MMBtu for each month during that period.

(2) EOG has entered into natural gas derivative contracts which give counterparties the option of entering into derivative contracts at future dates. Additionally, in connection with certain natural gas derivative contracts settled in July 2012, counterparties retain an option of entering into derivative contracts at future dates. All such options are exercisable monthly up until the settlement date of each monthly contract. If the counterparties exercise all such options, the notional volume of EOG's existing natural gas derivative contracts will increase by 320,000 MMBtud at an average price of $4.66 per MMBtu for each month during the period January 1, 2014 through December 31, 2014.

Foreign Currency Exchange Rate Derivative. EOG is party to a foreign currency aggregate swap with multiple banks to eliminate any exchange rate impacts that may result from the 4.75% Subsidiary Debt issued by one of EOG's Canadian subsidiaries. The foreign currency swap agreement expires on March 15, 2014. EOG accounts for the foreign currency swap transaction using the hedge accounting method. Changes in the fair value of the foreign currency swap do not impact Net Income. The after-tax net impact from the foreign currency swap resulted in increases in Other Comprehensive Income (OCI) of $1.5 million and $1.1 million for the three months ended September 30, 2013 and 2012, respectively, and increases in OCI of $2.5 million and $1.7 million for the nine months ended September 30, 2013 and 2012, respectively.

Interest Rate Derivative. EOG is a party to an interest rate swap with a counterparty bank. The interest rate swap was entered into in order to mitigate EOG's exposure to volatility in interest rates related to the Floating Rate Notes. The interest rate swap has a notional amount of $350 million and expires on February 3, 2014. EOG accounts for the interest rate swap transaction using the hedge accounting method. Changes in the fair value of the interest rate swap do not impact Net Income. The after-tax net impact from the interest rate swap resulted in an increase in OCI of $0.4 million and a reduction in OCI of $0.2 million for the three months ended September 30, 2013 and 2012, respectively, and an increase in OCI of $1.3 million and a reduction in OCI of $0.4 million for the nine months ended September 30, 2013 and 2012, respectively.

The following table sets forth the amounts and classification of EOG's outstanding derivative financial instruments at September 30, 2013 and December 31, 2012. Certain amounts may be presented on a net basis on the consolidated financial statements when such amounts are with the same counterparty and subject to a master netting arrangement (in millions):

Description	Location on Balance Sheet	Fair Value at September 30, 2013	Fair Value at December 31, 2012
Asset Derivatives			
Crude oil and natural gas derivative contracts -			
Current portion	Assets from Price Risk Management Activities (1)	$ 45	$ 166
Noncurrent portion	Other Assets (2)	$ 3	$ -
Liability Derivatives			
Crude oil and natural gas derivative contracts -			
Current portion	Liabilities from Price Risk Management Activities (3)	$ 175	$ 8
Noncurrent portion	Other Liabilities (4)	$ -	$ 13
Foreign currency swap -			
Current portion	Current Liabilities - Other	$ 46	$ -
Noncurrent portion	Other Liabilities	$ -	$ 55
Interest rate swap -			
Current portion	Current Liabilities - Other	$ 2	$ -
Noncurrent portion	Other Liabilities	$ -	$ 4

(1) The current portion of Assets from Price Risk Management Activities consists of gross assets of $47 million, partially offset by gross liabilities of $2 million at September 30, 2013 and gross assets of $271 million, partially offset by gross liabilities of $105 million at December 31, 2012.

(2) The noncurrent portion of Assets from Price Risk Management Activities consists of gross assets of $4 million, partially offset by gross liabilities of $1 million at September 30, 2013.

(3) The current portion of Liabilities from Price Risk Management Activities consists of gross liabilities of $177 million, partially offset by gross assets of $2 million at September 30, 2013 and gross liabilities of $113 million, partially offset by gross assets of $105 million at December 31, 2012.

(4) The noncurrent portion of Liabilities from Price Risk Management Activities consists of gross liabilities of $1 million, offset by gross assets of $1 million at September 30, 2013 and gross liabilities of $13 million at December 31, 2012.

Credit Risk. Notional contract amounts are used to express the magnitude of commodity price, foreign currency and interest rate swap agreements. The amounts potentially subject to credit risk, in the event of nonperformance by the counterparties, are equal to the fair value of such contracts (see Note 11). EOG evaluates its exposure to significant counterparties on an ongoing basis, including those arising from physical and financial transactions. In some instances, EOG requires collateral, parent guarantees or letters of credit to minimize credit risk.

All of EOG's outstanding derivative instruments are covered by International Swap Dealers Association Master Agreements (ISDAs) with counterparties. The ISDAs may contain provisions that require EOG, if it is the party in a net liability position, to post collateral when the amount of the net liability exceeds the threshold level specified for EOG's then-current credit ratings. In addition, the ISDAs may also provide that as a result of certain circumstances, including certain events that cause EOG's credit rating to become materially weaker than its then-current ratings, the counterparty may require all outstanding derivatives under the ISDAs to be settled immediately. See Note 11 for the aggregate fair value of all derivative instruments that were in a net liability position at September 30, 2013 and December 31, 2012. EOG held no collateral at September 30, 2013 and held $6 million of collateral at December 31, 2012. EOG had collateral of $2 million posted at September 30, 2013 and no collateral posted at December 31, 2012.

13. Divestitures

During the first nine months of 2013, EOG received proceeds of approximately $587 million primarily from the sale of its entire interest in the planned Kitimat liquefied natural gas export terminal and the proposed Pacific Trail Pipelines, undeveloped acreage in the Horn River Basin in Canada and producing properties and acreage in the Upper Gulf Coast region, the Mid-Continent area and the Permian Basin. During the first nine months of 2012, EOG received proceeds of approximately $1,214 million from sales of producing properties and acreage primarily in the Rocky Mountain area, the Upper Gulf Coast region and Canada.

PART I. FINANCIAL INFORMATION

ITEM 2. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS EOG RESOURCES, INC.

Overview

EOG Resources, Inc., together with its subsidiaries (collectively, EOG), is one of the largest independent (non-integrated) crude oil and natural gas companies in the United States with proved reserves in the United States, Canada, Trinidad, the United Kingdom, China and Argentina. EOG operates under a consistent business and operational strategy that focuses predominantly on maximizing the rate of return on investment of capital by controlling operating and capital costs and maximizing reserve recoveries. This strategy is intended to enhance the generation of cash flow and earnings from each unit of production on a cost-effective basis, allowing EOG to deliver long-term production growth while maintaining a strong balance sheet. EOG implements its strategy by emphasizing the drilling of internally generated prospects in order to find and develop low-cost reserves. Maintaining the lowest possible operating cost structure that is consistent with prudent and safe operations is also an important goal in the implementation of EOG’s strategy.

United States and Canada. EOG's efforts to identify plays with large reserve potential have proven to be successful. EOG continues to drill numerous wells in large acreage plays, which in the aggregate are expected to contribute substantially to EOG's crude oil and liquids-rich natural gas production. EOG has placed an emphasis on applying its horizontal drilling and completion expertise to unconventional crude oil and liquids-rich reservoirs. In 2013, EOG is focused on developing its existing North American crude oil and liquids-rich acreage and testing methods to improve the recovery factor of the oil-in-place in these plays. In addition, EOG continues to evaluate certain potential crude oil and liquids-rich exploration and development prospects. For the first nine months of 2013, revenues from the sales of crude oil and condensate and natural gas liquids (NGLs) were approximately 84% of total wellhead revenues. On a volumetric basis, as calculated using the ratio of 1.0 barrel of crude oil and condensate or NGLs to 6.0 thousand cubic feet of natural gas, crude oil and condensate and NGLs production accounted for approximately 55% of total company production for the first nine months of 2013 as compared to 45% for the comparable period in 2012. In North America, crude oil and condensate and NGLs production accounted for approximately 62% of total North American production during the first nine months of 2013 as compared to 52% for the comparable period in 2012. This liquids growth primarily reflects increased production from the South Texas Eagle Ford, the Permian Basin and the North Dakota Bakken. Based on current trends, EOG expects its 2013 crude oil and condensate and NGLs production to continue to increase both in total and as a percentage of total company production as compared to 2012. In 2013, EOG's major producing areas in the United States and Canada are in New Mexico, North Dakota, Texas, Utah, Wyoming and western Canada.

EOG continues to deliver its crude oil to various markets in the United States, including sales points on the Gulf Coast where sales are based upon the premium Light Louisiana Sweet crude oil index. EOG's crude-by-rail facilities provide EOG the ability to direct its crude oil shipments via rail car to the most favorable markets, including the Gulf Coast, Cushing, Oklahoma, and other markets.

In December 2012, EOG's wholly-owned Canadian subsidiary signed a purchase and sale agreement for the sale of its entire interest in the planned Kitimat liquefied natural gas export terminal, the proposed Pacific Trail Pipelines and approximately 28,500 undeveloped net acres in the Horn River Basin. The transaction closed in February 2013.

International. In Trinidad, EOG continued to deliver natural gas under existing supply contracts. Several fields in the South East Coast Consortium Block, Modified U(a) Block, Block 4(a) and Modified U(b) Block, as well as in the Pelican Field and the EMZ Area, have been developed and are producing natural gas sold to the National Gas Company of Trinidad and Tobago and condensate sold to the Petroleum Company of Trinidad and Tobago. During the first nine months of 2013, EOG continued its four-well program in the Modified U(a) Block, drilling three development wells and one successful exploratory well. In the third quarter of 2013, three of the four wells began production. The fourth well will begin production in the fourth quarter of 2013. In addition, an existing well was recompleted and began production in the third quarter of 2013.

In the United Kingdom, EOG continues to make progress in field development for its East Irish Sea Conwy crude oil discovery. Modifications to the nearby third-party-owned Douglas platform, which will be used to process Conwy production, began in the first quarter of 2013. In the third quarter of 2013, a crude oil processing module was installed on the Douglas platform. In addition, drilling began on three development wells. First production from the Conwy field is anticipated in late 2014. In the second quarter of 2013, costs totaling $24.1 million associated with the Central North Sea Columbus natural gas project were written off. In the third quarter of 2013, EOG drilled an unsuccessful exploratory well in the Central North Sea Block 21/12b which was awarded to EOG in 2009.

In Argentina, EOG is focused on the Vaca Muerta oil shale formation in the Neuquén Basin in Neuquén Province. In 2012, a monitor well was drilled in the Aguada del Chivato Block and completed during the first half of 2013. Also, in 2013, the first well on the Cerro Avispa Block was drilled with completion expected in the fourth quarter of 2013. EOG continues to evaluate its drilling results and exploration program in Argentina.

During the first half of 2013, EOG successfully recompleted a well in the Sichuan Basin, Sichuan Province, The People's Republic of China. A second well was drilled in the third quarter of 2013 and will be completed in the fourth quarter of 2013. One additional well is planned in the fourth quarter of 2013, which is expected to begin producing in 2014.

EOG continues to evaluate other select crude oil and natural gas opportunities outside the United States and Canada primarily by pursuing exploitation opportunities in countries where indigenous crude oil and natural gas reserves have been identified.

Capital Structure. One of management's key strategies is to maintain a strong balance sheet with a consistently below average debt-to-total capitalization ratio as compared to those in EOG's peer group. EOG's debt-to-total capitalization ratio was 30% and 32% at September 30, 2013 and December 31, 2012, respectively. As used in this calculation, total capitalization represents the sum of total current and long-term debt and total stockholders' equity. At September 30, 2013, $350 million principal amount of Floating Rate Senior Notes due 2014 and $150 million principal amount of 4.75% Subsidiary Debt due 2014 were classified as long-term debt based upon EOG's intent and ability to ultimately replace such amounts with other long-term debt. On October 1, 2013, EOG repaid, at maturity, the $400 million principal amount of its 6.125% Senior Notes.

EOG's total anticipated 2013 capital expenditures are estimated to range from $7.0 billion to $7.2 billion, excluding acquisitions. The majority of 2013 expenditures have been and will be focused on United States crude oil and, to a lesser extent, liquids-rich natural gas drilling activity. EOG expects capital expenditures to be slightly higher than cash flow from operating activities for 2013. EOG's business plan includes an objective of selling certain non-core assets in 2013 to cover any anticipated shortfall in cash flows. In the first nine months of 2013, EOG achieved this goal by receiving proceeds of approximately $587 million from sales of assets. EOG has significant flexibility with respect to financing alternatives, including borrowings under its commercial paper program and other uncommitted credit facilities, bank borrowings, borrowings under its $2.0 billion senior unsecured revolving credit facility and equity and debt offerings. When it fits EOG's strategy, EOG will make acquisitions that bolster existing drilling programs or offer incremental exploration and/or production opportunities. Management continues to believe EOG has one of the strongest prospect inventories in EOG's history.

Results of Operations

The following review of operations for the three and nine months ended September 30, 2013 and 2012 should be read in conjunction with the consolidated financial statements of EOG and notes thereto included in this Quarterly Report on Form 10-Q.

Three Months Ended September 30, 2013 vs. Three Months Ended September 30, 2012

Net Operating Revenues. During the third quarter of 2013, net operating revenues increased $586 million, or 20%, to $3,541 million from $2,955 million for the same period of 2012. Total wellhead revenues, which are revenues generated from sales of EOG's production of crude oil and condensate, NGLs and natural gas, for the third quarter of 2013 increased $833 million, or 39%, to $2,942 million from $2,109 million for the same period of 2012. During the third quarter of 2013, EOG recognized net losses on the mark-to-market of financial commodity derivative contracts of $293 million compared to net gains of $5 million for the same period of 2012. Gathering, processing and marketing revenues, which are revenues generated from sales of third-party crude oil and condensate, NGLs and natural gas as well as fees associated with gathering third-party natural gas, for the third quarter of 2013 increased $109 million, or 14%, to $873 million from $764 million for the same period of 2012. Gains on asset dispositions, net, for the third quarter of 2013 and 2012 totaled $8 million and $67 million, respectively.

Wellhead volume and price statistics for the three-month periods ended September 30, 2013 and 2012 were as follows:

	Three Months Ended September 30,	
	2013	2012
Crude Oil and Condensate Volumes (MBbld) (1)		
United States	227.6	161.3
Canada	6.1	6.7
Trinidad	1.2	1.2
Other International (2)	0.1	0.1
Total	235.0	169.3
Average Crude Oil and Condensate Prices ($/Bbl) (3)		
United States	$ 108.56	$ 97.64
Canada	97.90	86.09
Trinidad	94.96	90.84
Other International (2)	81.30	83.59
Composite	108.20	97.13
Natural Gas Liquids Volumes (MBbld) (1)		
United States	68.2	58.1
Canada	0.9	0.9
Total	69.1	59.0
Average Natural Gas Liquids Prices ($/Bbl) (3)		
United States	$ 32.75	$ 30.95
Canada	32.24	41.09
Composite	32.74	31.11
Natural Gas Volumes (MMcfd) (1)		
United States	899	1,022
Canada	76	94
Trinidad	352	387
Other International (2)	7	9
Total	1,334	1,512
Average Natural Gas Prices ($/Mcf) (3)		
United States	$ 3.19	$ 2.61
Canada	2.61	2.39
Trinidad	3.41	4.38
Other International (2)	6.12	5.67
Composite	3.23	3.07
Crude Oil Equivalent Volumes (MBoed) (4)		
United States	445.7	389.7
Canada	19.7	23.2
Trinidad	59.8	65.7
Other International (2)	1.2	1.7
Total	526.4	480.3
Total MMBoe (4)	48.4	44.2

(1) Thousand barrels per day or million cubic feet per day, as applicable.
(2) Other International includes EOG's United Kingdom, China and Argentina operations.
(3) Dollars per barrel or per thousand cubic feet, as applicable. Excludes the impact of financial commodity derivative instruments.
(4) Thousand barrels of oil equivalent per day or million barrels of oil equivalent, as applicable; includes crude oil and condensate, natural gas liquids and natural gas. Crude oil equivalents are determined using the ratio of 1.0 barrel of crude oil and condensate or natural gas liquids to 6.0 thousand cubic feet of natural gas. MMBoe is calculated by multiplying the MBoed amount by the number of days in the period and then dividing that amount by one thousand.

Wellhead crude oil and condensate revenues for the third quarter of 2013 increased $826 million, or 55%, to $2,338 million from $1,512 million for the same period of 2012, due to an increase of 66 MBbld, or 39%, in wellhead crude oil and condensate deliveries ($587 million) and a higher composite average wellhead crude oil and condensate price ($239 million). The increase in deliveries primarily reflects increased production in the South Texas Eagle Ford, the North Dakota Bakken and the Permian Basin. EOG's composite average wellhead crude oil and condensate price for the third quarter of 2013 increased 11% to $108.20 per barrel compared to $97.13 per barrel for the same period of 2012.

NGLs revenues for the third quarter of 2013 increased $38 million, or 22%, to $208 million from $170 million for the same period of 2012, due to an increase of 10 MBbld, or 17%, in NGLs deliveries ($28 million) and a higher composite average NGLs price ($10 million). The increase in deliveries primarily reflects increased volumes in the South Texas Eagle Ford and the Permian Basin. EOG's composite average NGLs price for the third quarter of 2013 increased 5% to $32.74 per barrel compared to $31.11 per barrel for the same period of 2012.

Wellhead natural gas revenues for the third quarter of 2013 decreased $31 million, or 7%, to $396 million from $427 million for the same period of 2012. The decrease was due to a decrease in natural gas deliveries ($50 million), partially offset by a higher composite average wellhead natural gas price ($19 million). EOG's composite average wellhead natural gas price for the third quarter of 2013 increased 5% to $3.23 per thousand cubic feet (Mcf) compared to $3.07 per Mcf for the same period of 2012. Natural gas deliveries for the third quarter of 2013 decreased 178 MMcfd, or 12%, primarily due to lower production in the United States (123 MMcfd), Trinidad (35 MMcfd) and Canada (18 MMcfd). The decrease in the United States was primarily attributable to asset sales and reduced natural gas drilling activity. The decrease in Trinidad was primarily attributable to higher contractual deliveries in 2012.

During the third quarter of 2013, EOG recognized net losses on the mark-to-market of financial commodity derivative contracts of $293 million compared to net gains of $5 million for the same period of 2012. During the third quarter of 2013, the net cash outflow related to settled crude oil and natural gas derivative contracts was $21 million compared to the net cash inflow of $249 million for the same period of 2012.

Gathering, processing and marketing revenues represent sales of third-party crude oil and condensate, NGLs and natural gas, as well as fees associated with gathering third-party natural gas. Gathering, processing and marketing revenues were primarily related to sales of third-party crude oil and natural gas. Purchases and sales of third-party crude oil and natural gas are utilized in order to balance firm transportation capacity with production in certain areas and to utilize excess capacity at EOG-owned facilities. Marketing costs represent the costs of purchasing third-party crude oil and natural gas and the associated transportation costs.

During the third quarter of 2013, gathering, processing and marketing revenues and marketing costs increased compared to the same period of 2012 primarily as a result of increased crude oil marketing activities. Gathering, processing and marketing revenues less marketing costs for the third quarter of 2013 decreased $13 million compared to the same period of 2012 due to lower margins on crude oil marketing activities.

Operating and Other Expenses. For the third quarter of 2013, operating expenses of $2,772 million were $423 million higher than the $2,349 million incurred during the third quarter of 2012. The following table presents the costs per barrel of oil equivalent (Boe) for the three-month periods ended September 30, 2013 and 2012:

	Three Months Ended September 30,	
	2013	**2012**
Lease and Well	$ 6.18	$ 5.73
Transportation Costs	4.54	3.72
Depreciation, Depletion and Amortization (DD&A) -		
Oil and Gas Properties	18.65	17.86
Other Property, Plant and Equipment	0.53	0.81
General and Administrative (G&A)	2.04	2.10
Interest Expense, Net	1.23	1.20
Total (1)	$ 33.17	$ 31.42

(1) Total excludes gathering and processing costs, exploration costs, dry hole costs, impairments, marketing costs and taxes other than income.

The primary factors impacting the cost components of per-unit rates of lease and well, transportation costs, DD&A, G&A and interest expense, net, for the three months ended September 30, 2013, compared to the same period of 2012 are set forth below.

Lease and well expenses include expenses for EOG-operated properties, as well as expenses billed to EOG from other operators where EOG is not the operator of a property. Lease and well expenses can be divided into the following categories: costs to operate and maintain crude oil and natural gas wells, the cost of workovers and lease and well administrative expenses. Operating and maintenance costs include, among other things, pumping services, salt water disposal, equipment repair and maintenance, compression expense, lease upkeep and fuel and power. Workovers are operations to restore or maintain production from existing wells.

Each of these categories of costs individually fluctuates from time to time as EOG attempts to maintain and increase production while maintaining efficient, safe and environmentally responsible operations. EOG continues to increase its operating activities by drilling new wells in existing and new areas. Operating and maintenance costs within these existing and new areas, as well as the costs of services charged to EOG by vendors, fluctuate over time. In general, operating and maintenance costs for wells producing crude oil are higher than operating and maintenance costs for wells producing natural gas.

Lease and well expenses of $299 million for the third quarter of 2013 increased $46 million from $253 million for the same prior year period primarily due to increased operating and maintenance costs in the United States ($25 million) and Canada ($5 million) and increased workover expenditures in the United States ($15 million).

Transportation costs represent costs associated with the delivery of hydrocarbon products from the lease to a downstream point of sale. Transportation costs include transportation fees, costs associated with crude-by-rail operations, the cost of compression (the cost of compressing natural gas to meet pipeline pressure requirements), dehydration (the cost associated with removing water from natural gas to meet pipeline requirements), gathering fees and fuel costs.

Transportation costs of $220 million for the third quarter of 2013 increased $56 million from $164 million for the same prior year period primarily due to increased transportation costs related to production from the South Texas Eagle Ford ($29 million), the Rocky Mountain area ($18 million) and the Fort Worth Basin Barnett Shale area ($9 million).

DD&A of the cost of proved oil and gas properties is calculated using the unit-of-production method. EOG's DD&A rate and expense are the composite of numerous individual DD&A group calculations. There are several factors that can impact EOG's composite DD&A rate and expense, such as field production profiles, drilling or acquisition of new wells, disposition of existing wells, reserve revisions (upward or downward) primarily related to well performance, economic factors and impairments. Changes to these factors may cause EOG's composite DD&A rate and expense to fluctuate from year to year. DD&A of the cost of other property, plant and equipment is generally calculated using the straight-line depreciation method over the useful lives of the assets.

DD&A expenses for the third quarter of 2013 increased $103 million to $929 million from $826 million for the same prior year period. DD&A expenses associated with oil and gas properties for the third quarter of 2013 were $113 million higher than the same prior year period primarily as a result of increased production in the United States ($97 million) and higher unit rates in the United States ($25 million) and Trinidad ($9 million), partially offset by decreased production in Canada ($8 million) and Trinidad ($4 million). Unit rates in the United States increased due primarily to downward revisions of natural gas reserves at December 31, 2012, and an increase in production from higher-cost properties.

G&A expenses of $99 million for the third quarter of 2013 increased $6 million compared to the same prior year period primarily due to higher costs associated with supporting expanding operations.

Interest expense, net, of $59 million for the third quarter of 2013 increased $6 million compared to the same prior year period primarily due to interest charges related to $1.25 billion aggregate principal amount of the 2.625% Senior Notes due 2023 issued in September 2012.

Gathering and processing costs represent operating and maintenance expenses and administrative expenses associated with operating EOG's gathering and processing assets.

Gathering and processing costs increased $5 million to $31 million for the third quarter of 2013 compared to $26 million for the same prior year period. The increase primarily reflects increased activities in the South Texas Eagle Ford.

Exploration costs of $39 million for the third quarter of 2013 decreased $7 million from $46 million for the same prior year period primarily due to decreased geological and geophysical expenditures in the United States.

Impairments include amortization of unproved oil and gas property costs, as well as impairments of proved oil and gas properties and other assets. Unproved properties with acquisition costs that are not individually significant are aggregated, and the portion of such costs estimated to be nonproductive is amortized over the remaining lease term. When circumstances indicate that a proved property may be impaired, EOG compares expected undiscounted future cash flows at a DD&A group level to the unamortized capitalized cost of the asset. If the expected future undiscounted cash flows are lower than the unamortized capitalized cost, the capitalized cost is reduced to fair value. Fair value is generally calculated by using the Income Approach as described in the Fair Value Measurement Topic of the Financial Accounting Standards Board's Accounting Standards Codification. For certain assets held for sale, EOG utilized accepted bids as the basis for determining fair value.

Impairments of $86 million for the third quarter of 2013 were $23 million higher than impairments for the same prior year period primarily due to increased impairments of other assets in the United States ($30 million) and increased amortization of unproved property costs in the United States ($3 million), partially offset by decreased impairments of proved properties in the United States ($10 million). EOG recorded impairments of proved properties and other assets of $55 million and $33 million for the third quarter of 2013 and 2012, respectively.

Taxes other than income include severance/production taxes, ad valorem/property taxes, payroll taxes, franchise taxes and other miscellaneous taxes. Severance/production taxes are generally determined based on wellhead revenues, and ad valorem/property taxes are generally determined based on the valuation of the underlying assets.

Taxes other than income for the third quarter of 2013 increased $52 million to $172 million (5.9% of wellhead revenues) compared to $120 million (5.7% of wellhead revenues) for the same prior year period. The increase in taxes other than income was primarily due to increased severance/production taxes in the United States ($44 million) primarily as a result of increased wellhead revenues and increased ad valorem/property taxes in the United States ($8 million).

Income tax provision of $259 million for the third quarter of 2013 increased $54 million compared to the same period of 2012 due primarily to higher pretax income. The net effective tax rate for the third quarter of 2013 decreased to 36% from 37% for the same prior year period.

Nine Months Ended September 30, 2013 vs. Nine Months Ended September 30, 2012

Net Operating Revenues. During the first nine months of 2013, net operating revenues increased $2,067 million, or 24%, to $10,738 million from $8,671 million for the same period of 2012. Total wellhead revenues for the first nine months of 2013 increased $2,087 million, or 36%, to $7,958 million from $5,871 million for the same period of 2012. During the first nine months of 2013, EOG recognized net losses on the mark-to-market of financial commodity derivative contracts of $207 million compared to net gains of $327 million for the same period of 2012. Gathering, processing and marketing revenues for the first nine months of 2013 increased $562 million, or 26%, to $2,755 million from $2,193 million for the same period of 2012. Gains on asset dispositions, net, for the first nine months of 2013 and 2012 totaled $186 million and $248 million, respectively.

Wellhead volume and price statistics for the nine-month periods ended September 30, 2013 and 2012 were as follows:

	Nine Months Ended September 30,	
	2013	2012
Crude Oil and Condensate Volumes (MBbld)		
United States	204.3	147.6
Canada	6.7	6.9
Trinidad	1.3	1.7
Other International	0.1	0.1
Total	212.4	156.3
Average Crude Oil and Condensate Prices ($/Bbl) (1)		
United States	$ 106.36	$ 98.26
Canada	90.53	86.25
Trinidad	91.80	93.85
Other International	88.90	90.34
Composite	105.76	97.68
Natural Gas Liquids Volumes (MBbld)		
United States	63.5	54.3
Canada	0.9	0.9
Total	64.4	55.2
Average Natural Gas Liquids Prices ($/Bbl)		
United States	$ 31.55	$ 35.43
Canada	37.83	44.61
Composite	31.64	35.58
Natural Gas Volumes (MMcfd)		
United States	920	1,051
Canada	78	98
Trinidad	350	393
Other International	8	10
Total	1,356	1,552
Average Natural Gas Prices ($/Mcf) (1)		
United States	$ 3.33	$ 2.39
Canada	3.01	2.35
Trinidad	3.71	3.60
Other International	6.58	5.70
Composite	3.43	2.71
Crude Oil Equivalent Volumes (MBoed)		
United States	421.2	377.2
Canada	20.7	24.1
Trinidad	59.5	67.1
Other International	1.4	1.8
Total	502.8	470.2
Total MMBoe	137.3	128.8

(1) Excludes the impact of financial commodity derivative instruments.

Wellhead crude oil and condensate revenues for the first nine months of 2013 increased $1,934 million, or 46%, to $6,133 million from $4,199 million for the same period of 2012, due to an increase of 56 MBbld, or 36%, in wellhead crude oil and condensate deliveries ($1,465 million) and a higher composite average wellhead crude oil and condensate price ($469 million). The increase in deliveries primarily reflects increased production in the South Texas Eagle Ford, the Permian Basin and the North Dakota Bakken. EOG's composite average wellhead crude oil and condensate price for the first nine months of 2013 increased 8% to $105.76 per barrel compared to $97.68 per barrel for the same period of 2012.

NGLs revenues for the first nine months of 2013 increased $37 million, or 7%, to $556 million from $519 million for the same period of 2012, due to an increase of 9 MBbld, or 17%, in NGLs deliveries ($106 million), partially offset by a lower composite average NGLs price ($69 million). The increase in deliveries primarily reflects increased volumes in the South Texas Eagle Ford and the Permian Basin. EOG's composite average NGLs price for the first nine months of 2013 decreased 11% to $31.64 per barrel compared to $35.58 per barrel for the same period of 2012.

Wellhead natural gas revenues for the first nine months of 2013 increased $117 million, or 10%, to $1,270 million from $1,153 million for the same period of 2012. The increase was due to a higher composite average wellhead natural gas price ($266 million), partially offset by decreased natural gas deliveries ($149 million). EOG's composite average wellhead natural gas price for the first nine months of 2013 increased 27% to $3.43 per Mcf compared to $2.71 per Mcf for the same period of 2012. Natural gas deliveries for the first nine months of 2013 decreased 196 MMcfd, or 13%, primarily due to decreased production in the United States (131 MMcfd), Trinidad (43 MMcfd) and Canada (20 MMcfd). The decrease in the United States was attributable to asset sales and reduced natural gas drilling activity. The decrease in Trinidad was primarily attributable to higher contractual deliveries in 2012.

During the first nine months of 2013, EOG recognized net losses on the mark-to-market of financial commodity derivative contracts of $207 million compared to net gains of $327 million for the same period of 2012. During the first nine months of 2013, the net cash inflow related to settled crude oil and natural gas derivative contracts was $115 million compared to the net cash inflow of $556 million for the same period of 2012.

During the first nine months of 2013, gathering, processing and marketing revenues and marketing costs increased, compared to the same period of 2012, primarily as a result of increased crude oil marketing activities. Gathering, processing and marketing revenues less marketing costs for the first nine months of 2013 decreased $30 million compared to the same period of 2012 due to lower margins on crude oil marketing activities.

Operating and Other Expenses. For the first nine months of 2013, operating expenses of $8,043 million were $1,230 million higher than the $6,813 million incurred during the same period of 2012. The following table presents the costs per Boe for the nine-month periods ended September 30, 2013 and 2012:

	Nine Months Ended September 30,	
	2013	**2012**
Lease and Well	$ 5.95	$ 5.96
Transportation Costs	4.58	3.36
DD&A -		
Oil and Gas Properties	19.00	17.72
Other Property, Plant and Equipment	0.57	0.84
G&A	1.87	1.91
Interest Expense, Net	1.33	1.20
Total (1)	$ 33.30	$ 30.99

(1) Total excludes gathering and processing costs, exploration costs, dry hole costs, impairments, marketing costs and taxes other than income.

The primary factors impacting the cost components of per-unit rates of lease and well, transportation costs, DD&A, G&A and interest expense, net, for the nine months ended September 30, 2013, compared to the same period of 2012 are set forth below.

Lease and well expenses of $817 million for the first nine months of 2013 increased $51 million from $766 million for the same prior year period primarily due to increased operating and maintenance costs in the United States ($21 million) and Canada ($7 million), increased workover expenditures in the United States ($15 million) and increased lease and well administrative expenses ($8 million).

Transportation costs of $629 million for the first nine months of 2013 increased $197 million from $432 million for the same prior year period primarily due to increased transportation costs related to production from the South Texas Eagle Ford ($93 million), the Rocky Mountain area ($73 million) and the Fort Worth Basin Barnett Shale area ($30 million).

DD&A expenses for the first nine months of 2013 increased $303 million to $2,686 million from $2,383 million for the same prior year period. DD&A expenses associated with oil and gas properties for the first nine months of 2013 were $332 million higher than the same prior year period primarily as a result of increased production in the United States ($229 million) and higher unit rates in the United States ($125 million) and Trinidad ($32 million), partially offset by decreased production in Canada ($25 million) and Trinidad ($12 million) and lower unit rates in Canada ($16 million). Unit rates in the United States increased due primarily to downward revisions of natural gas reserves at December 31, 2012, and an increase in production from higher-cost properties.

G&A expenses of $257 million for the first nine months of 2013 increased $12 million compared to the same prior year period primarily due to higher costs associated with supporting expanding operations.

Interest expense, net of $183 million for the first nine months of 2013 increased $29 million compared to the same prior year period primarily due to a higher average debt balance.

Gathering and processing costs for the first nine months of 2013 increased $9 million to $82 million compared to the same prior year period primarily due to increased activities in the South Texas Eagle Ford.

Exploration costs of $131 million for the first nine months of 2013 decreased $6 million from $137 million for the same prior year period primarily due to decreased geological and geophysical expenditures in the United States ($9 million) and Canada ($2 million), partially offset by increased exploration administrative expenses in the United States ($5 million).

Impairments of $177 million for the first nine months of 2013 were $73 million lower than impairments for the same prior year period primarily due to decreased impairments of proved properties in the United States ($87 million) and decreased amortization of unproved property costs in the United States ($14 million) and Canada ($4 million), partially offset by increased impairments of proved properties in Canada ($12 million) and Argentina ($6 million) and increased impairments of other assets in the United States ($11 million). EOG recorded impairments of proved properties and other assets of $93 million and $148 million for the first nine months of 2013 and 2012, respectively.

Taxes other than income for the first nine months of 2013 increased $99 million to $459 million (5.8% of wellhead revenues) from $360 million (6.1% of wellhead revenues) for the same prior year period. The increase in taxes other than income was primarily due to increased severance/production taxes in the United States ($86 million) primarily as a result of increased wellhead revenues, higher ad valorem/property taxes in the United States ($15 million) and a decrease in credits available to EOG in 2013 for Texas high-cost gas severance tax rate reductions ($4 million), partially offset by decreased severance/production taxes in Trinidad ($3 million) and Canada ($2 million).

Other income, net, was $6 million for the first nine months of 2013 compared to $23 million for the same prior year period. The decrease of $17 million was primarily due to losses related to warehouse stock sales and adjustments ($12 million) and an increase in deferred compensation expense ($4 million).

Income tax provision of $901 million for the first nine months of 2013 increased $250 million compared to the same period of 2012 due primarily to higher pretax income. The net effective tax rate for the first nine months of 2013 decreased to 36% from 38% for the same prior year period.

Capital Resources and Liquidity

Cash Flow. The primary sources of cash for EOG during the nine months ended September 30, 2013, were funds generated from operations, proceeds from asset sales, excess tax benefits from stock-based compensation and proceeds from stock options exercised and employee stock purchase plan activity. The primary uses of cash were funds used in operations; exploration and development expenditures; other property, plant and equipment expenditures; dividend payments to stockholders; and purchases of treasury stock in connection with stock compensation plans. During the first nine months of 2013, EOG's cash balance increased $443 million to $1,319 million from $876 million at December 31, 2012.

Net cash provided by operating activities of $5,328 million for the first nine months of 2013 increased $1,319 million compared to the same period of 2012 primarily reflecting an increase in wellhead revenues ($2,087 million), favorable changes in working capital and other assets and liabilities ($38 million), and a decrease in net cash paid for income taxes ($37 million), partially offset by an unfavorable change in net cash flow from the settlement of financial commodity derivative contracts ($441 million), an increase in cash operating expenses ($356 million) and an increase in net cash paid for interest expense ($41 million).

Net cash used in investing activities of $4,763 million for the first nine months of 2013 increased by $85 million compared to the same period of 2012 due primarily to a decrease in proceeds from sales of assets ($626 million) and an increase in restricted cash ($68 million); partially offset by a decrease in additions to oil and gas properties ($243 million); a decrease in additions to other property, plant and equipment ($206 million); and favorable changes in working capital associated with investing activities ($161 million).

Net cash used in financing activities of $127 million for the first nine months of 2013 included cash dividend payments ($148 million) and purchases of treasury stock in connection with stock compensation plans ($56 million). Cash provided by financing activities for the first nine months of 2013 included excess tax benefits from stock-based compensation ($50 million) and proceeds from stock options exercised and employee stock purchase plan activity ($30 million). Net cash provided by financing activities of $1,161 million for the first nine months of 2012 included net proceeds from long-term debt borrowings ($1,234 million), proceeds from stock options exercised and employee stock purchase plan activity ($60 million), and excess tax benefits from stock-based compensation ($49 million). Cash used in financing activities for the first nine months of 2012 included cash dividend payments ($134 million) and purchases of treasury stock in connection with stock compensation plans ($45 million).

Total Expenditures. For the year 2013, EOG's budget for exploration and development and other property, plant and equipment expenditures is approximately $7.0 billion to $7.2 billion, excluding acquisitions. The table below sets out components of total expenditures for the nine-month periods ended September 30, 2013 and 2012 (in millions):

	Nine Months Ended September 30,		
	2013	**2012**	
Expenditure Category			
Capital			
Drilling and Facilities	$ 4,596	$ 4,894	
Leasehold Acquisitions	309	382	
Property Acquisitions	92	-	
Capitalized Interest	34	37	
Subtotal	5,031	5,313	
Exploration Costs	131	137	
Dry Hole Costs	59	13	
Exploration and Development Expenditures	5,221	5,463	
Asset Retirement Costs	69	62	
Total Exploration and Development Expenditures	5,290	5,525	
Other Property, Plant and Equipment	271	543	(1)
Total Expenditures	$ 5,561	$ 6,068	

(1) Includes non-cash additions of $66 million in connection with a capital lease transaction in the South Texas Eagle Ford.

Exploration and development expenditures of $5,221 million for the first nine months of 2013 were $242 million lower than the same period of 2012 due primarily to decreased drilling and facilities expenditures in the United States ($312 million), Canada ($97 million) and Argentina ($32 million); decreased leasehold acquisition expenditures in the United States ($45 million) and Canada ($28 million); and decreased exploration geological and geophysical expenditures in the United States ($9 million). These decreases were partially offset by increased property acquisition expenditures in the United States ($92 million) and increased drilling and facilities expenditures in Trinidad ($86 million), the United Kingdom ($50 million) and China ($12 million). The exploration and development expenditures for the first nine months of 2013 of $5,221 million consist of $4,524 million in development, $571 million in exploration, $92 million in property acquisitions and $34 million in capitalized interest. The exploration and development expenditures for the first nine months of 2012 of $5,463 million consist of $4,758 million in development, $668 million in exploration and $37 million in capitalized interest.

The level of exploration and development expenditures, including acquisitions, will vary in future periods depending on energy market conditions and other related economic factors. EOG has significant flexibility with respect to financing alternatives and the ability to adjust its exploration and development expenditure budget as circumstances warrant. While EOG has certain continuing commitments associated with expenditure plans related to its operations, such commitments are not expected to be material when considered in relation to the total financial capacity of EOG.

Commodity Derivative Transactions. As more fully discussed in Note 11 to the Consolidated Financial Statements included in EOG's Annual Report on Form 10-K for the year ended December 31, 2012, filed on February 22, 2013, EOG engages in price risk management activities from time to time. These activities are intended to manage EOG's exposure to fluctuations in commodity prices for crude oil and natural gas. EOG utilizes financial commodity derivative instruments, primarily price swap, option, swaption, collar and basis swap contracts, as a means to manage this price risk. EOG has not designated any of its financial commodity derivative contracts as accounting hedges and, accordingly, accounts for financial commodity derivative contracts using the mark-to-market accounting method. Under this accounting method, changes in the fair value of outstanding financial instruments are recognized as gains or losses in the period of change and are recorded as (Losses) Gains on Mark-to-Market Commodity Derivative Contracts on the Consolidated Statements of Income and Comprehensive Income. The related cash flow impact is reflected in Cash Flows from Operating Activities. In addition to financial transactions, from time to time EOG is a party to various physical commodity contracts for the sale of hydrocarbons that cover varying periods of time and have varying pricing provisions. The financial impact of physical commodity contracts is included in revenues at the time of settlement, which in turn affects average realized hydrocarbon prices.

Commodity Derivative Contracts. The total fair value of EOG's crude oil and natural gas derivative contracts was reflected on the Consolidated Balance Sheets at September 30, 2013 as a net liability of $127 million. EOG entered into additional crude oil derivative contracts since filing its Current Report on Form 8-K on October 10, 2013. In addition, during September 2013, EOG settled certain crude oil derivative contracts covering notional volumes of 5,000 barrels per day (Bbld) for the period July 1, 2014 through December 31, 2014. Presented below is a comprehensive summary of EOG's crude oil derivative contracts at November 6, 2013, with notional volumes expressed in Bbld and prices expressed in dollars per barrel ($/Bbl).

Crude Oil Derivative Contracts		
	Volume (Bbld)	Weighted Average Price ($/Bbl)
2013 [1]		
January 2013 (closed)	101,000	$ 99.29
February 1, 2013 through April 30, 2013 (closed)	109,000	99.17
May 1, 2013 through June 30, 2013 (closed)	101,000	99.29
July 2013 (closed)	111,000	98.25
August 1, 2013 through October 31, 2013 (closed)	126,000	98.80
November 1, 2013 through December 31, 2013	126,000	98.80
2014 [2]		
January 1, 2014 through March 31, 2014	128,000	$ 96.44
April 1, 2014 through June 30, 2014	118,000	96.43
July 1, 2014 through December 31, 2014	9,000	95.30

(1) EOG has entered into crude oil derivative contracts which give counterparties the option to extend certain current derivative contracts for an additional six-month period. Options covering a notional volume of 64,000 Bbld are exercisable on December 31, 2013. If the counterparties exercise all such options, the notional volume of EOG's existing crude oil derivative contracts will increase by 64,000 Bbld at an average price of $99.58 per barrel for each month during the period January 1, 2014 through June 30, 2014.

(2) EOG has entered into crude oil derivative contracts which give counterparties the option to extend certain current derivative contracts for additional six-month and nine-month periods. Options covering a notional volume of 10,000 Bbld are exercisable on or about March 31, 2014. If the counterparties exercise all such options, the notional volume of EOG's existing crude oil derivative contracts will increase by 10,000 Bbld at an average price of $96.60 per barrel for each month during the period April 1, 2014 through December 31, 2014. Options covering a notional volume of 103,000 Bbld are exercisable on or about June 30, 2014. If the counterparties exercise all such options, the notional volume of EOG's existing crude oil derivative contracts will increase by 103,000 Bbld at an average price of $96.60 per barrel for each month during the period July 1, 2014 through December 31, 2014. Options covering a notional volume of 9,000 Bbld are exercisable on or about December 31, 2014. In addition, in connection with the crude oil derivative contracts settled in September 2013 covering a notional volume of 5,000 Bbld, counterparties retain the option to enter into derivative contracts on December 31, 2014. If the counterparties exercise all such options, the notional volume of EOG's existing crude oil derivative contracts will increase by 14,000 Bbld at an average price of $95.35 per barrel for each month during the period January 1, 2015 through June 30, 2015.

Presented below is a comprehensive summary of EOG's natural gas derivative contracts at November 6, 2013, with notional volumes expressed in million British thermal units (MMBtu) per day (MMBtud) and prices expressed in dollars per MMBtu ($/MMBtu).

Natural Gas Derivative Contracts

	Volume (MMBtud)		Weighted Average Price ($/MMBtu)
2013 [1]			
January 1, 2013 through April 30, 2013 (closed)	150,000	$	4.79
May 1, 2013 through October 31, 2013 (closed)	200,000		4.72
November 2013 (closed)	150,000		4.79
December 2013	150,000		4.79
2014 [2]			
January 1, 2014 through December 31, 2014	170,000	$	4.54

(1) EOG has entered into natural gas derivative contracts which give counterparties the option of entering into derivative contracts at future dates. Such options are exercisable monthly up until the settlement date of each monthly contract. For December 2013, if the counterparties exercise all such options, the notional volume of EOG's existing natural gas derivative contracts will increase by 150,000 MMBtud at an average price of $4.79 per MMBtu.

(2) EOG has entered into natural gas derivative contracts which give counterparties the option of entering into derivative contracts at future dates. Additionally, in connection with certain natural gas derivative contracts settled in July 2012, counterparties retain an option of entering into derivative contracts at future dates. All such options are exercisable monthly up until the settlement date of each monthly contract. If the counterparties exercise all such options, the notional volume of EOG's existing natural gas derivative contracts will increase by 320,000 MMBtud at an average price of $4.66 per MMBtu for each month during the period January 1, 2014 through December 31, 2014.

Information Regarding Forward-Looking Statements

This Quarterly Report on Form 10-Q includes forward-looking statements within the meaning of Section 27A of the Securities Act of 1933, as amended, and Section 21E of the Securities Exchange Act of 1934, as amended. All statements, other than statements of historical facts, including, among others, statements and projections regarding EOG's future financial position, operations, performance, business strategy, returns, budgets, reserves, levels of production and costs, statements regarding future commodity prices and statements regarding the plans and objectives of EOG's management for future operations, are forward-looking statements. EOG typically uses words such as "expect," "anticipate," "estimate," "project," "strategy," "intend," "plan," "target," "goal," "may," "will," "should" and "believe" or the negative of those terms or other variations or comparable terminology to identify its forward-looking statements. In particular, statements, express or implied, concerning EOG's future operating results and returns or EOG's ability to replace or increase reserves, increase production, generate income or cash flows or pay dividends are forward-looking statements. Forward-looking statements are not guarantees of performance. Although EOG believes the expectations reflected in its forward-looking statements are reasonable and are based on reasonable assumptions, no assurance can be given that these assumptions are accurate or that any of these expectations will be achieved (in full or at all) or will prove to have been correct. Moreover, EOG's forward-looking statements may be affected by known, unknown or currently unforeseen risks, events or circumstances that may be outside EOG's control. Important factors that could cause EOG's actual results to differ materially from the expectations reflected in EOG's forward-looking statements include, among others:

- the timing and extent of changes in prices for, and demand for, crude oil and condensate, NGLs, natural gas and related commodities;
- the extent to which EOG is successful in its efforts to acquire or discover additional reserves;
- the extent to which EOG can optimize reserve recovery and economically develop its plays utilizing horizontal and vertical drilling, advanced completion technologies and hydraulic fracturing;
- the extent to which EOG is successful in its efforts to economically develop its acreage in, and to produce reserves and achieve anticipated production levels from, its existing and future crude oil and natural gas exploration and development projects, given the risks and uncertainties and capital expenditure requirements inherent in drilling, completing and operating crude oil and natural gas wells and the potential for interruptions of development and production, whether involuntary or intentional as a result of market or other conditions;
- the extent to which EOG is successful in its efforts to market its crude oil, natural gas and related commodity production;
- the availability, proximity and capacity of, and costs associated with, gathering, processing, compression and transportation facilities;
- the availability, cost, terms and timing of issuance or execution of, and competition for, mineral licenses and leases and governmental and other permits and rights-of-way, and EOG’s ability to retain mineral licenses and leases;
- the impact of, and changes in, government policies, laws and regulations, including tax laws and regulations, environmental laws and regulations relating to air emissions, waste disposal, hydraulic fracturing and access to and use of water, laws and regulations imposing conditions and restrictions on drilling and completion operations and laws and regulations with respect to derivatives and hedging activities;
- EOG's ability to effectively integrate acquired crude oil and natural gas properties into its operations, fully identify existing and potential problems with respect to such properties and accurately estimate reserves, production and costs with respect to such properties;
- the extent to which EOG's third-party-operated crude oil and natural gas properties are operated successfully and economically;
- competition in the oil and gas exploration and production industry for employees and other personnel, equipment, materials and services and, related thereto, the availability and cost of employees and other personnel, equipment, materials and services;
- the accuracy of reserve estimates, which by their nature involve the exercise of professional judgment and may therefore be imprecise;

- weather, including its impact on crude oil and natural gas demand, and weather-related delays in drilling and in the installation and operation of production, gathering, processing, compression and transportation facilities;
- the ability of EOG's customers and other contractual counterparties to satisfy their obligations to EOG and, related thereto, to access the credit and capital markets to obtain financing needed to satisfy their obligations to EOG;
- EOG's ability to access the commercial paper market and other credit and capital markets to obtain financing on terms it deems acceptable, if at all, and to otherwise satisfy its capital expenditure requirements;
- the extent and effect of any hedging activities engaged in by EOG;
- the timing and extent of changes in foreign currency exchange rates, interest rates, inflation rates, global and domestic financial market conditions and global and domestic general economic conditions;
- political conditions and developments around the world (such as political instability and armed conflict), including in the areas in which EOG operates;
- the use of competing energy sources and the development of alternative energy sources;
- the extent to which EOG incurs uninsured losses and liabilities or losses and liabilities in excess of its insurance coverage;
- acts of war and terrorism and responses to these acts;
- physical, electronic and cyber security breaches; and
- the other factors described under Item 1A, "Risk Factors," on pages 16 through 23 of EOG's Annual Report on Form 10-K for the year ended December 31, 2012.

In light of these risks, uncertainties and assumptions, the events anticipated by EOG's forward-looking statements may not occur, and, if any of such events do, we may not have anticipated the timing of their occurrence or the extent of their impact on our actual results. Accordingly, you should not place any undue reliance on any of EOG's forward-looking statements. EOG's forward-looking statements speak only as of the date made, and EOG undertakes no obligation, other than as required by applicable law, to update or revise its forward-looking statements, whether as a result of new information, subsequent events, anticipated or unanticipated circumstances or otherwise.

PART I. FINANCIAL INFORMATION

ITEM 3. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK
EOG RESOURCES, INC.

EOG's exposure to commodity price risk, interest rate risk and foreign currency exchange rate risk is discussed in (i) the "Derivative Transactions," "Financing," "Foreign Currency Exchange Rate Risk" and "Outlook" sections of "Management's Discussion and Analysis of Financial Condition and Results of Operations - Capital Resources and Liquidity" on pages 42 through 47 of EOG's Annual Report on Form 10-K for the year ended December 31, 2012, filed on February 22, 2013 (EOG's 2012 Annual Report); and (ii) Note 11, "Risk Management Activities," to EOG's Consolidated Financial Statements on pages F-25 through F-28 of EOG's 2012 Annual Report. There have been no material changes in this information. For additional information regarding EOG's financial commodity derivative contracts and physical commodity contracts, see (i) Note 12, "Risk Management Activities," to EOG's Consolidated Financial Statements in this Quarterly Report on Form 10-Q; (ii) "Management's Discussion and Analysis of Financial Condition and Results of Operations - Results of Operations - Net Operating Revenues" in this Quarterly Report on Form 10-Q; and (iii) "Management's Discussion and Analysis of Financial Condition and Results of Operations - Capital Resources and Liquidity - Commodity Derivative Transactions" in this Quarterly Report on Form 10-Q.

ITEM 4. CONTROLS AND PROCEDURES
EOG RESOURCES, INC.

Disclosure Controls and Procedures. EOG's management, with the participation of EOG's principal executive officer and principal financial officer, evaluated the effectiveness of EOG's disclosure controls and procedures (as defined in Rules 13a-15(e) and 15d-15(e) promulgated under the Securities Exchange Act of 1934, as amended (Exchange Act)) as of the end of the period covered by this Quarterly Report on Form 10-Q (Evaluation Date). Based on this evaluation, EOG's principal executive officer and principal financial officer have concluded that EOG's disclosure controls and procedures were effective as of the Evaluation Date in ensuring that information that is required to be disclosed in the reports EOG files or furnishes under the Exchange Act is (i) recorded, processed, summarized and reported within the time periods specified in the United States Securities and Exchange Commission's rules and forms and (ii) accumulated and communicated to EOG's management, as appropriate, to allow timely decisions regarding required disclosure.

Internal Control Over Financial Reporting. There were no changes in EOG's internal control over financial reporting (as defined in Rules 13a-15(f) and 15d-15(f) promulgated under the Exchange Act) that occurred during the quarterly period covered by this Quarterly Report on Form 10-Q that have materially affected, or are reasonably likely to materially affect, EOG's internal control over financial reporting.

PART II. OTHER INFORMATION

EOG RESOURCES, INC.

ITEM 1. LEGAL PROCEEDINGS

See Part I, Item 1, Note 8 to Consolidated Financial Statements, which is incorporated herein by reference.

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

The following table sets forth, for the periods indicated, EOG's share repurchase activity:

Period	Total Number of Shares Purchased (1)	Average Price Paid Per Share	Total Number of Shares Purchased as Part of Publicly Announced Plans or Programs	Maximum Number of Shares that May Yet Be Purchased Under The Plans or Programs (2)
July 1, 2013 – July 31, 2013	21,447	$ 142.17	-	6,386,200
August 1, 2013 – August 31, 2013	58,542	156.09	-	6,386,200
September 1, 2013 – September 30, 2013	131,120	168.15	-	6,386,200
Total	211,109	162.17	-	

(1) Represents shares that were withheld by or returned to EOG (i) in satisfaction of tax withholding obligations that arose upon the exercise of employee stock options or stock-settled stock appreciation rights or the vesting of restricted stock or restricted stock unit grants or (ii) in payment of the exercise price of employee stock options. These shares do not count against the 10 million aggregate share authorization by EOG's Board of Directors (Board) discussed below.

(2) In September 2001, the Board authorized the repurchase of up to 10 million shares of EOG's common stock. During the third quarter of 2013, EOG did not repurchase any shares under the Board-authorized repurchase program.

ITEM 4. MINE SAFETY DISCLOSURES

The information concerning mine safety violations and other regulatory matters required by Section 1503(a) of the Dodd-Frank Wall Street Reform and Consumer Protection Act and Item 104 of Regulation S-K (17 CFR 229.104) is included in Exhibit 95 to this report.

ITEM 6. EXHIBITS

Exhibit No.		Description
* 10.1	-	Third Amendment to Amended and Restated Change of Control Agreement between EOG and Mark G. Papa, effective as of September 4, 2013.
* 10.2	-	Second Amendment to Change of Control Agreement between EOG and William R. Thomas, effective as of September 4, 2013.
* 10.3	-	Third Amendment to Amended and Restated Change of Control Agreement between EOG and Gary L. Thomas, effective as of September 4, 2013.
* 10.4	-	First Amendment to Change of Control Agreement between EOG and Lloyd W. Helms, Jr., effective as of September 4, 2013.
* 10.5	-	Change of Control Agreement by and between EOG and David W. Trice, effective as of September 4, 2013.
* 10.6	-	Third Amendment to Amended and Restated Change of Control Agreement between EOG and Timothy K. Driggers, effective as of September 4, 2013.
* 10.7	-	First Amendment to Change of Control Agreement between EOG and Michael P. Donaldson, effective as of September 4, 2013.
* 10.8	-	First Amendment to the EOG Resources, Inc. 409A Deferred Compensation Plan, effective as of January 1, 2012.
* 31.1	-	Section 302 Certification of Periodic Report of Principal Executive Officer.
* 31.2	-	Section 302 Certification of Periodic Report of Principal Financial Officer.
* 32.1	-	Section 906 Certification of Periodic Report of Principal Executive Officer.
* 32.2	-	Section 906 Certification of Periodic Report of Principal Financial Officer.
* 95	-	Mine Safety Disclosure Exhibit.

Exhibit No.		**Description**
* **101.INS	-	XBRL Instance Document.
* **101.SCH	-	XBRL Schema Document.
* **101.CAL	-	XBRL Calculation Linkbase Document.
* **101.DEF	-	XBRL Definition Linkbase Document.
* **101.LAB	-	XBRL Label Linkbase Document.
* **101.PRE	-	XBRL Presentation Linkbase Document.

* Exhibits filed herewith

** Attached as Exhibit 101 to this report are the following documents formatted in XBRL (Extensible Business Reporting Language): (i) the Consolidated Statements of Income and Comprehensive Income - Three Months Ended September 30, 2013 and 2012 and Nine Months Ended September 30, 2013 and 2012, (ii) the Consolidated Balance Sheets - September 30, 2013 and December 31, 2012, (iii) the Consolidated Statements of Cash Flows - Nine Months Ended September 30, 2013 and 2012 and (iv) Notes to Consolidated Financial Statements.

SIGNATURES

Pursuant to the requirements of the Securities Exchange Act of 1934, as amended, the registrant has duly caused this report to be signed on its behalf by the undersigned thereunto duly authorized.

EOG RESOURCES, INC.
(Registrant)

Date: November 6, 2013

By: /s/ TIMOTHY K. DRIGGERS
Timothy K. Driggers
Vice President and Chief Financial Officer
(Principal Financial Officer and Duly Authorized Officer)

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