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, 2012

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	270,880,999 as of October 31, 2012

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, 2012	Three Months Ended September 30, 2011	Nine Months Ended September 30, 2012	Nine Months Ended September 30, 2011
Net Operating Revenues				
Crude Oil and Condensate	$ 1,512,168	$ 953,154	$ 4,198,753	$ 2,649,034
Natural Gas Liquids	170,351	206,572	518,684	539,104
Natural Gas	426,728	576,803	1,153,433	1,760,715
Gains on Mark-to-Market Commodity Derivative Contracts	4,671	357,664	327,328	480,539
Gathering, Processing and Marketing	764,385	578,022	2,193,290	1,461,303
Gains on Asset Dispositions, Net	67,376	207,468	248,134	442,981
Other, Net	9,176	6,061	31,203	19,424
Total	2,954,855	2,885,744	8,670,825	7,353,100
Operating Expenses				
Lease and Well	253,452	248,926	765,703	680,710
Transportation Costs	164,407	108,678	431,642	308,276
Gathering and Processing Costs	26,223	18,532	72,403	55,444
Exploration Costs	45,953	48,469	136,909	140,616
Dry Hole Costs	1,924	22,604	13,005	47,231
Impairments	62,875	83,431	250,239	531,413
Marketing Costs	755,457	572,604	2,155,043	1,427,450
Depreciation, Depletion and Amortization	825,851	651,684	2,383,359	1,822,854
General and Administrative	92,870	82,260	244,866	219,703
Taxes Other Than Income	120,096	98,526	359,798	308,669
Total	2,349,108	1,935,714	6,812,967	5,542,366
Operating Income	605,747	950,030	1,857,858	1,810,734
Other Income, Net	7,596	1,377	22,902	11,205
Income Before Interest Expense and Income Taxes	613,343	951,407	1,880,760	1,821,939
Interest Expense, Net	53,154	52,186	154,198	153,772
Income Before Income Taxes	560,189	899,221	1,726,562	1,668,167
Income Tax Provision	204,698	358,343	651,284	697,742
Net Income	$ 355,491	$ 540,878	$ 1,075,278	$ 970,425
Net Income Per Share				
Basic	$ 1.33	$ 2.03	$ 4.03	$ 3.71
Diluted	$ 1.31	$ 2.01	$ 3.98	$ 3.66
Dividends Declared per Common Share	$ 0.17	$ 0.16	$ 0.51	$ 0.48
Average Number of Common Shares				
Basic	267,941	266,053	267,136	261,664
Diluted	270,982	269,292	270,328	265,245
Comprehensive Income				
Net Income	$ 355,491	$ 540,878	$ 1,075,278	$ 970,425
Other Comprehensive Income (Loss)				
Foreign Currency Translation Adjustments	50,426	(119,338)	48,262	(63,823)
Foreign Currency Swap	1,708	646	2,338	462
Income Tax Related to Foreign Currency Swap	(646)	(166)	(597)	(114)
Interest Rate Swap	(318)	(2,503)	(682)	(6,612)
Income Tax Related to Interest Rate Swap	114	901	245	2,378
Other	29	28	87	86
Other Comprehensive Income (Loss)	51,313	(120,432)	49,653	(67,623)
Comprehensive Income	$ 406,804	$ 420,446	$ 1,124,931	$ 902,802

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, 2012	December 31, 2011
ASSETS		
Current Assets		
Cash and Cash Equivalents	$ 1,112,623	$ 615,726
Accounts Receivable, Net	1,579,841	1,451,227
Inventories	657,880	590,594
Assets from Price Risk Management Activities	248,698	450,730
Income Taxes Receivable	54,049	26,609
Deferred Income Taxes	120,967	-
Other	226,104	119,052
Total	4,000,162	3,253,938
Property, Plant and Equipment		
Oil and Gas Properties (Successful Efforts Method)	37,021,216	33,664,435
Other Property, Plant and Equipment	2,609,467	2,149,989
Total Property, Plant and Equipment	39,630,683	35,814,424
Less: Accumulated Depreciation, Depletion and Amortization	(15,944,233)	(14,525,600)
Total Property, Plant and Equipment, Net	23,686,450	21,288,824
Other Assets	345,879	296,035
Total Assets	$ 28,032,491	$ 24,838,797
LIABILITIES AND STOCKHOLDERS' EQUITY		
Current Liabilities		
Accounts Payable	$ 2,151,093	$ 2,033,615
Accrued Taxes Payable	168,691	147,105
Dividends Payable	45,653	42,578
Deferred Income Taxes	2,793	135,989
Other	210,153	163,032
Total	2,578,383	2,522,319
Long-Term Debt	6,305,277	5,009,166
Other Liabilities	842,173	799,189
Deferred Income Taxes	4,513,188	3,867,219
Commitments and Contingencies (Note 8)		
Stockholders' Equity		
Common Stock, $0.01 Par, 640,000,000 Shares Authorized and 271,323,486 Shares Issued at September 30, 2012 and 269,323,084 Shares Issued at December 31, 2011	202,713	202,693
Additional Paid in Capital	2,459,531	2,272,052
Accumulated Other Comprehensive Income	451,399	401,746
Retained Earnings	10,726,811	9,789,345
Common Stock Held in Treasury, 473,624 Shares at September 30, 2012 and 303,633 Shares at December 31, 2011	(46,984)	(24,932)
Total Stockholders' Equity	13,793,470	12,640,904
Total Liabilities and Stockholders' Equity	$ 28,032,491	$ 24,838,797

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, 2012	Nine Months Ended September 30, 2011
Cash Flows from Operating Activities		
Reconciliation of Net Income to Net Cash Provided by Operating Activities:		
Net Income	$ 1,075,278	$ 970,425
Items Not Requiring (Providing) Cash		
Depreciation, Depletion and Amortization	2,383,359	1,822,854
Impairments	250,239	531,413
Stock-Based Compensation Expenses	101,337	95,057
Deferred Income Taxes	385,878	499,279
Gains on Asset Dispositions, Net	(248,134)	(442,981)
Other, Net	(10,266)	2,270
Dry Hole Costs	13,005	47,231
Mark-to-Market Commodity Derivative Contracts		
Total Gains	(327,328)	(480,539)
Realized Gains	555,946	83,765
Excess Tax Benefits from Stock-Based Compensation	(49,426)	-
Other, Net	12,675	21,052
Changes in Components of Working Capital and Other Assets and Liabilities		
Accounts Receivable	(112,174)	(128,965)
Inventories	(154,766)	(167,611)
Accounts Payable	83,682	245,385
Accrued Taxes Payable	42,791	101,239
Other Assets	(120,085)	(28,600)
Other Liabilities	39,871	37,022
Changes in Components of Working Capital Associated with Investing and Financing Activities	87,708	133,227
Net Cash Provided by Operating Activities	4,009,590	3,341,523
Investing Cash Flows		
Additions to Oil and Gas Properties	(5,326,884)	(4,665,535)
Additions to Other Property, Plant and Equipment	(477,351)	(502,112)
Proceeds from Sales of Assets	1,213,550	1,294,627
Changes in Components of Working Capital Associated with Investing Activities	(87,654)	(133,512)
Net Cash Used in Investing Activities	(4,678,339)	(4,006,532)
Financing Cash Flows		
Common Stock Sold	-	1,388,270
Long-Term Debt Borrowings	1,234,138	-
Dividends Paid	(134,412)	(124,133)
Excess Tax Benefits from Stock-Based Compensation	49,426	-
Treasury Stock Purchased	(44,799)	(21,357)
Proceeds from Stock Options Exercised and Employee Stock Purchase Plan	59,714	26,887
Debt Issuance Costs	(1,771)	-
Repayment of Capital Lease Obligation	(1,407)	-
Other, Net	(54)	285
Net Cash Provided by Financing Activities	1,160,835	1,269,952
Effect of Exchange Rate Changes on Cash	4,811	(7,068)
Increase in Cash and Cash Equivalents	496,897	597,875
Cash and Cash Equivalents at Beginning of Period	615,726	788,853
Cash and Cash Equivalents at End of Period	$ 1,112,623	$ 1,386,728

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

EOG RESOURCES, INC.
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
(Unaudited)

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, 2011, filed on February 24, 2012 (EOG's 2011 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, 2012 are not necessarily indicative of the results to be expected for the full year.

Recently Issued Accounting Standards. In May 2011, the Financial Accounting Standards Board (FASB) issued Accounting Standards Update (ASU) 2011-04, "Fair Value Measurement (Topic 820): Amendments to Achieve Common Fair Value Measurement and Disclosure Requirements in U.S. GAAP and IFRSs." ASU 2011-04 amends the Fair Value Measurement Topic of the Accounting Standards Codification (ASC) to clarify the FASB's intent about the application of existing fair value measurement requirements and change certain principles or requirements for measuring fair value or disclosing information about fair value measurements. ASU 2011-04 became effective for interim and annual fiscal periods beginning after December 15, 2011. The adoption of ASU 2011-04 did not have a material impact on EOG's financial statements.

In June 2011, the FASB issued ASU 2011-05, "Comprehensive Income (Topic 220): Presentation of Comprehensive Income." ASU 2011-05 is intended to increase the prominence of comprehensive income in the financial statements by requiring that an entity that reports items of comprehensive income do so in either one continuous or two consecutive financial statements. ASU 2011-05 also requires separate presentation on the face of the financial statements for items reclassified from other comprehensive income into net income. Subsequently, in December 2011, the FASB deferred the effective date of the provisions of ASU 2011-05 relating to the presentation of reclassification adjustments out of accumulated other comprehensive income. The provisions of ASU 2011-05 not deferred by the FASB became effective for interim and annual fiscal periods beginning after December 15, 2011. Retroactive application is required. The adoption of ASU 2011-05 did not have a material impact on EOG's financial statements.

2. Stock-Based Compensation

As more fully discussed in Note 6 to the Consolidated Financial Statements included in EOG's 2011 Annual Report, EOG maintains various stock-based compensation plans. Stock-based compensation expense is included in the Consolidated Statements of Income and Comprehensive Income based upon the job function of the employee receiving the grants as follows (in millions):

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2012	2011	2012	2011
Lease and Well	$ 9.9	$ 9.5	$ 26.4	$ 24.4
Gathering and Processing Costs	0.3	0.2	0.8	0.6
Exploration Costs	7.4	7.8	20.3	19.4
General and Administrative	28.3	24.1	53.8	50.6
Total	$ 45.9	$ 41.6	$ 101.3	$ 95.0

The EOG Resources, Inc. 2008 Omnibus Equity Compensation Plan, as amended (2008 Plan), provides for grants of stock options, stock-settled stock appreciation rights (SARs), restricted stock, restricted stock units and other stock-based awards. At September 30, 2012, approximately 3.3 million common shares remained available for grant under the 2008 Plan. EOG's policy is to issue shares related to the 2008 Plan from 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 all 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 $16.5 million and $13.5 million during the three months ended September 30, 2012 and 2011, respectively, and $37.8 million and $33.4 million during the nine months ended September 30, 2012 and 2011, 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, 2012 and 2011 were as follows:

	Stock Options/SARs Nine Months Ended September 30,		ESPP Nine Months Ended September 30,	
	2012	2011	2012	2011
Weighted Average Fair Value of Grants	$ 37.94	$ 29.87	$ 25.17	$ 22.35
Expected Volatility	39.68%	40.92%	41.04%	29.68%
Risk-Free Interest Rate	0.45%	0.58%	0.11%	0.18%
Dividend Yield	0.6%	0.7%	0.6%	0.7%
Expected Life	5.6 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, 2012 and 2011 (stock options and SARs in thousands):

	Nine Months Ended September 30, 2012		Nine Months Ended September 30, 2011	
	Number of Stock Options/SARs	Weighted Average Grant Price	Number of Stock Options/SARs	Weighted Average Grant Price
Outstanding at January 1	8,374	$ 70.01	8,445	$ 64.49
Granted	1,223	111.91	1,470	85.25
Exercised (1)	(2,044)	53.52	(1,150)	48.41
Forfeited	(124)	89.95	(133)	87.75
Outstanding at September 30 (2)	7,429	$ 81.11	8,632	$ 69.80
Vested or Expected to Vest (3)	7,184	$ 80.57	8,387	$ 69.29
Exercisable at September 30 (4)	4,315	$ 69.87	5,382	$ 59.25

(1) The total intrinsic value of stock options/SARs exercised for the nine months ended September 30, 2012 and 2011 was $110.8 million and $69.3 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, 2012 and 2011 was $231.1 million and $91.0 million, respectively. At September 30, 2012 and 2011, the weighted average remaining contractual life was 4.1 years and 3.9 years, respectively.
(3) The total intrinsic value of stock options/SARs vested or expected to vest at September 30, 2012 and 2011 was $227.3 million and $91.0 million, respectively. At September 30, 2012 and 2011, the weighted average remaining contractual life was 4.0 years and 3.8 years, respectively.
(4) The total intrinsic value of stock options/SARs exercisable at September 30, 2012 and 2011 was $182.7 million and $90.9 million, respectively. At September 30, 2012 and 2011, the weighted average remaining contractual life was 2.7 years and 2.6 years, respectively.

At September 30, 2012, unrecognized compensation expense related to non-vested stock option and SAR grants totaled $100.7 million. This unrecognized expense will be amortized on a straight-line basis over a weighted average period of 2.8 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 units totaled $23.1 million and $28.1 million for the three months ended September 30, 2012 and 2011, respectively, and $57.2 million and $61.6 million for the nine months ended September 30, 2012 and 2011, respectively.

The following table sets forth restricted stock and restricted stock units transactions for the nine-month periods ended September 30, 2012 and 2011 (shares and units in thousands):

	Nine Months Ended September 30, 2012			Nine Months Ended September 30, 2011		
	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	4,240	$	82.93	4,009	$	79.13
Granted	757		112.13	917		90.93
Released (1)	(977)		72.97	(410)		65.77
Forfeited	(106)		88.36	(202)		82.51
Outstanding at September 30 (2)	3,914	$	90.91	4,314	$	82.75

(1) The total intrinsic value of restricted stock and restricted stock units released for the nine months ended September 30, 2012 and 2011 was $110.7 million and $40.0 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, 2012 and 2011 was $438.6 million and $306.4 million, respectively.

At September 30, 2012, unrecognized compensation expense related to restricted stock and restricted stock units totaled $151.8 million. Such unrecognized expense will be amortized on a straight-line basis over a weighted average period of 2.5 years.

Performance Units and Performance Stock. In September 2012, as a new element of the long-term incentive component of EOG's executive officer compensation program, EOG granted an aggregate of 54,526 performance units and 16,752 shares of performance stock to its executive officers (in each case under the terms of the 2008 Plan), which units and shares remained outstanding at September 30, 2012. As more fully discussed in the grant agreements, the performance metric applicable to these performance-based grants is EOG's total shareholder return over a three-year performance period relative to the total shareholder return of a designated group of peer companies. Upon the application of the performance multiple at the completion of the performance period, a minimum of zero and a maximum of 142,556 performance units/shares could be outstanding. Subject to the termination provisions set forth in the grant agreements and the applicable performance multiple, the grants of performance units/shares will "cliff" vest five years from the date of grant.

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 $6.3 million for both the three months and nine months ended September 30, 2012. Weighted average fair values and valuation assumptions used to value performance unit and performance stock grants for the nine months ended September 30, 2012 were: Weighted Average Fair Value of Grants, $134.09; Expected Volatility, 36.39%; Risk-Free Interest Rate, 0.39%; and Dividend Yield, 0.06%.

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.

At September 30, 2012, unrecognized compensation expense related to performance units and performance stock totaled $3.1 million. Such unrecognized expense will be amortized on a straight-line basis over a weighted average period of 3.3 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, 2012 and 2011 (in thousands, except per share data):

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2012	2011	2012	2011
Numerator for Basic and Diluted Earnings Per Share -				
Net Income	$ 355,491	$ 540,878	$ 1,075,278	$ 970,425
Denominator for Basic Earnings Per Share -				
Weighted Average Shares	267,941	266,053	267,136	261,664
Potential Dilutive Common Shares -				
Stock Options/SARs	1,343	1,479	1,517	1,759
Restricted Stock/Units and Performance Units/Stock	1,698	1,760	1,675	1,822
Denominator for Diluted Earnings Per Share -				
Adjusted Diluted Weighted Average Shares	270,982	269,292	270,328	265,245
Net Income Per Share				
Basic	$ 1.33	$ 2.03	$ 4.03	$ 3.71
Diluted	$ 1.31	$ 2.01	$ 3.98	$ 3.66

The diluted earnings per share calculation excludes stock options and SARs that were anti-dilutive. Shares underlying the excluded stock options and SARs totaled 0.5 million and 0.6 million shares for the three months ended September 30, 2012 and 2011, respectively, and 0.3 million and 0.4 million shares for the nine months ended September 30, 2012 and 2011, 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, 2012 and 2011 (in thousands):

	Nine Months Ended September 30,	
	2012	2011
Interest [(1)]	$ 132,264	$ 111,111
Income Taxes, Net of Refunds Received	$ 257,046	$ 148,937

(1) Net of capitalized interest of $37 million and $44 million for the nine months ended September 30, 2012 and 2011, respectively.

EOG's accrued capital expenditures at September 30, 2012 and 2011 were $725 million and $747 million, respectively.

Non-cash investing and financing activities for the nine months ended September 30, 2012 included non-cash additions of $66 million to EOG's other property, plant and equipment and related obligations in connection with a capital lease transaction (see Note 10).

5. Segment Information

Selected financial information by reportable segment is presented below for the three-month and nine-month periods ended September 30, 2012 and 2011 (in thousands):

	Three Months Ended September 30, 2012	Three Months Ended September 30, 2011	Nine Months Ended September 30, 2012	Nine Months Ended September 30, 2011
Net Operating Revenues				
United States	$ 2,702,046	$ 2,640,739	$ 7,953,839	$ 6,549,392
Canada	79,500	103,842	264,059	360,380
Trinidad	167,402	134,542	434,746	421,884
Other International [1]	5,907	6,621	18,181	21,444
Total	$ 2,954,855	$ 2,885,744	$ 8,670,825	$ 7,353,100
Operating Income (Loss)				
United States	$ 545,982	$ 923,810	$ 1,711,860	$ 1,938,349
Canada	(40,477)	(36,596)	(93,113)	(356,012)
Trinidad	114,709	96,304	284,869	279,413
Other International [1]	(14,467)	(33,488)	(45,758)	(51,016)
Total	605,747	950,030	1,857,858	1,810,734
Reconciling Items				
Other Income, Net	7,596	1,377	22,902	11,205
Interest Expense, Net	53,154	52,186	154,198	153,772
Income Before Income Taxes	$ 560,189	$ 899,221	$ 1,726,562	$ 1,668,167

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

Total assets by reportable segment are presented below at September 30, 2012 and December 31, 2011 (in thousands):

	At September 30, 2012	At December 31, 2011
Total Assets		
United States	$ 24,313,164	$ 21,313,158
Canada	2,104,831	2,131,949
Trinidad	1,126,274	1,085,664
Other International [1]	488,222	308,026
Total	$ 28,032,491	$ 24,838,797

(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, 2012 and 2011 (in thousands):

	Nine Months Ended September 30, 2012	Nine Months Ended September 30, 2011
Carrying Amount at Beginning of Period	$ 587,084	$ 498,288
Liabilities Incurred	47,320	45,754
Liabilities Settled [1]	(56,150)	(58,084)
Accretion	22,714	20,125
Revisions	12,709	61,668
Foreign Currency Translations	5,140	(3,688)
Carrying Amount at End of Period	$ 618,817	$ 564,063
Current Portion	$ 27,615	$ 30,306
Noncurrent Portion	$ 591,202	$ 533,757

(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, 2012 are presented below (in thousands):

	Nine Months Ended September 30, 2012
Balance at December 31, 2011	$ 61,111
Additions Pending the Determination of Proved Reserves	69,533
Reclassifications to Proved Properties	(53,060)
Charged to Dry Hole Costs	(11,179)
Foreign Currency Translations	1,305
Balance at September 30, 2012	$ 67,710

The following table provides an aging of capitalized exploratory well costs at September 30, 2012 (in thousands, except well count):

		At September 30, 2012	
Capitalized exploratory well costs that have been capitalized for a period less than one year	$	40,650	
Capitalized exploratory well costs that have been capitalized for a period greater than one year		27,060	(1)
Total	$	67,710	
Number of exploratory wells that have been capitalized for a period greater than one year		2	

(1) Consists of costs related to an outside operated, offshore Central North Sea natural gas project in the United Kingdom (U.K.) ($21 million) and a shale project in the Horn River Basin area of British Columbia, Canada (B.C.) ($6 million). In the Central North Sea Columbus project, a revised field development plan was submitted to the U.K. Department of Energy and Climate Change during the third quarter of 2012. In the B.C. shale project, EOG drilled seven wells in the first nine months of 2012 to retain land and further evaluate the project.

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, 2012 and 2011, EOG's total costs recognized for these pension plans were $27.1 million and $20.6 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, 2012, EOG utilized commercial paper and short-term borrowings from uncommitted credit facilities, bearing market interest rates, for various corporate financing purposes. EOG had no outstanding borrowings from commercial paper issuances or uncommitted credit facilities at September 30, 2012. The average of the borrowings outstanding under the commercial paper program and uncommitted credit facilities was $315 million and $55 thousand, respectively, during the nine months ended September 30, 2012. The weighted average interest rates for commercial paper and uncommitted credit facility borrowings for the nine months ended September 30, 2012 were 0.45% and 0.70%, respectively.

On September 10, 2012, EOG closed its sale of $1.25 billion aggregate principal amount of its 2.625% Senior Notes due 2023 (Notes). Interest on the Notes is payable semi-annually in arrears on March 15 and September 15 of each year, beginning March 15, 2013. Net proceeds from the Notes offering of approximately $1,234 million were used for general corporate purposes, including repayment of outstanding commercial paper borrowings and funding of capital expenditures.

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, 2012, 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, 2012, the Eurodollar rate and applicable base rate, had there been any amounts borrowed under the Agreement, would have been 1.09% and 3.25%, respectively.

Capital Lease. During the third quarter of 2012, EOG began leasing certain newly constructed crude oil storage tanks located in the Eagle Ford Shale. The lease has an initial term of 10 years and EOG has an option to extend the lease for an additional 5-year period. It was determined that the lease qualifies as a capital lease for accounting purposes and, as a result, EOG has recognized a capital lease asset and a related liability of $66 million. The capital lease asset is included in Other Property, Plant and Equipment on the Consolidated Balance Sheets. The related liability is included in Long-Term Debt ($59 million) and Current Liabilities – Other ($7 million) on the Consolidated Balance Sheets. Total aggregate minimum lease payments are approximately $76 million over the initial term of the lease.

11. Fair Value Measurements

As more fully discussed in Note 12 to the Consolidated Financial Statements included in EOG's 2011 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, 2012 and December 31, 2011 (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, 2012				
Financial Assets:				
Crude Oil Derivative Contracts	$ -	$ 75	$ -	$ 75
Crude Oil Options/Swaptions	-	39	-	39
Natural Gas Derivative Contracts	-	20	-	20
Natural Gas Options/Swaptions	-	118	-	118
Financial Liabilities:				
Crude Oil Options/Swaptions	$ -	$ 1	$ -	$ 1
Natural Gas Options/Swaptions	-	6	-	6
Foreign Currency Rate Swap	-	57	-	57
Interest Rate Swap	-	4	-	4
At December 31, 2011				
Financial Assets:				
Crude Oil Derivative Contracts	$ -	$ 29	$ -	$ 29
Crude Oil Options/Swaptions	-	4	-	4
Natural Gas Derivative Contracts	-	81	-	81
Natural Gas Options/Swaptions	-	372	-	372
Financial Liabilities:				
Foreign Currency Rate Swap	$ -	$ 52	$ -	$ 52
Interest Rate Swap	-	3	-	3

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. Swaps were valued using market prices and discount rates from an independent third-party provider of financial market data. The Black 76 Model is utilized in valuing options.

The initial measurement of asset retirement obligations at fair value is calculated using discounted cash flow techniques and based on 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 property, plant and equipment with a carrying amount of $197 million were written down to their fair value of $87 million, resulting in a pretax impairment charge of $110 million for the nine months ended September 30, 2012. Included in the $110 million pretax impairment charge is a $60 million impairment of proved oil and gas properties and other property, plant and equipment, for which EOG utilized an accepted offer from a third-party 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 September 30, 2012 and December 31, 2011, EOG had outstanding $6,290 million and $5,040 million, respectively, aggregate principal amount of debt, which had estimated fair values of approximately $7,048 million and $5,657 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 2011 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, collar, option and basis swap contracts, as a means to manage this price risk. 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. Presented below is a comprehensive summary of EOG's crude oil derivative contracts at September 30, 2012, with notional volumes expressed in barrels per day (Bbld) and prices expressed in dollars per barrel ($/Bbl).

Crude Oil Derivative Contracts		
	Volume [(1)] (Bbld)	Weighted Average Price ($/Bbl)
2012		
January 1, 2012 through February 29, 2012 (closed)	34,000	$104.95
March 1, 2012 through June 30, 2012 (closed)	52,000	105.80
July 1, 2012 through August 31, 2012 (closed)	50,000	106.90
September 2012 (closed)	32,000	106.61
October 1, 2012 through December 31, 2012	42,000	105.19
2013		
January 1, 2013 through June 30, 2013	98,000	$ 99.39
July 1, 2013 through December 31, 2013	54,000	99.38

(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 25,000 Bbld are exercisable on December 31, 2012. If the counterparties exercise all such options, the notional volume of EOG's existing crude oil derivative contracts will increase by 25,000 Bbld at an average price of $106.27 per barrel for the period January 1, 2013 through June 30, 2013. Options covering a notional volume of 59,000 Bbld are exercisable on June 28, 2013. If the counterparties exercise all such options, the notional volume of EOG's existing crude oil derivative contracts will increase by 59,000 Bbld at an average price of $100.45 per barrel for the period July 1, 2013 through December 31, 2013. Options covering a notional volume of 15,000 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 15,000 Bbld at an average price of $103.54 per barrel for the period from January 1, 2014 through June 30, 2014.

Presented below is a comprehensive summary of EOG's natural gas derivative contracts at September 30, 2012, 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)
2012 (1)		
January 2012 through October 31, 2012 (closed)	525,000	$5.44
November 1, 2012 through December 31, 2012	525,000	5.44
2013 (2)		
January 1, 2013 through December 31, 2013	150,000	$4.79
2014 (3)		

(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. If the counterparties exercise all such options, the notional volume of EOG's existing natural gas derivative contracts will increase by 425,000 MMBtud at an average price of $5.44 per MMBtu for the period from November 1, 2012 through December 31, 2012.

(2) 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. 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 of 2013.

(3) In July 2012, EOG settled its natural gas derivative contracts for the period January 1, 2014 through December 31, 2014 and received proceeds of $36.6 million. In connection with these contracts, the counterparties retain an option of entering into derivative contracts at future dates. 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 150,000 MMBtud at an average price of $4.79 per MMBtu for each month of 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 $150 million principal amount of notes issued by one of EOG's Canadian subsidiaries. EOG accounts for the foreign currency swap 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 $1.1 million and $0.5 million for the three months ended September 30, 2012 and 2011, respectively, and increases in OCI of $1.7 million and $0.3 million for the nine months ended September 30, 2012 and 2011, 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 EOG's $350 million principal amount of Floating Rate Senior Notes due 2014. The interest rate swap has a notional amount of $350 million. EOG accounts for the interest rate swap 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 reductions in OCI of $0.2 million and $1.6 million for the three months ended September 30, 2012 and 2011, respectively, and reductions in OCI of $0.4 million and $4.2 million for the nine months ended September 30, 2012 and 2011, respectively.

The following table sets forth the amounts, on a gross basis, and classification of EOG's outstanding financial derivative instruments at September 30, 2012 and December 31, 2011. Certain amounts may be presented on a net basis in 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, 2012	Fair Value at December 31, 2011
Asset Derivatives			
Crude oil and natural gas derivative contracts -			
Current portion	Assets from Price Risk Management Activities	$ 238	$ 451
Noncurrent portion	Other Assets	14	35
Liability Derivatives			
Crude oil and natural gas derivative contracts -			
Current portion	Current Liabilities - Other	$ 1	$ -
Noncurrent portion	Other Liabilities	6	-
Foreign currency swap - Noncurrent portion	Other Liabilities	57	52
Interest rate swap - Noncurrent portion	Other Liabilities	4	3

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 are in a net liability position at September 30, 2012 and December 31, 2011. EOG had no collateral posted at either September 30, 2012 or December 31, 2011 and held no collateral at September 30, 2012. EOG held $67 million of collateral at December 31, 2011.

13. Divestitures

During the first nine months of 2012, EOG received proceeds of approximately $1,214 million from the sales of producing properties and acreage primarily in the Rocky Mountain area, the Upper Gulf Coast area 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 and China. 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 a successful supplement to its base development and exploitation program in the United States and Canada. 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 natural gas liquids production. EOG has placed an emphasis on applying its horizontal drilling and completion expertise gained from its natural gas resource plays to unconventional crude oil and liquids-rich reservoirs. In 2012, EOG continues to focus its efforts on developing its existing North American crude oil and liquids-rich acreage. In addition, EOG continues to evaluate certain potential liquids-rich exploration and development prospects. For the first nine months of 2012, crude oil and condensate and natural gas liquids production accounted for approximately 45% of total company production as compared to approximately 35% for the comparable period in 2011. In North America, crude oil and condensate and natural gas liquids production accounted for approximately 52% of total North American production during the first nine months of 2012 as compared to approximately 40% for the comparable period in 2011. This liquids growth primarily reflects increased production from the Eagle Ford Shale near San Antonio, Texas, the North Dakota Bakken, and the Permian Basin. Based on current trends, EOG expects its 2012 crude oil and condensate and natural gas liquids production to continue to increase both in total and as a percentage of total company production as compared to 2011.

EOG delivers its crude oil to various markets in the United States, including sales points on the Gulf Coast where sales are based upon a Light Louisiana Sweet (LLS) crude oil index. As part of its diversification strategy for its crude-by-rail shipments, in April 2012, EOG completed the construction of a crude oil unloading facility in St. James, Louisiana, where sales are based upon the LLS crude oil index. This facility, which received the first unit train of EOG crude oil in April 2012, has a capacity of approximately 100 thousand barrels per day (MBbld). With the addition of the St. James facility, EOG's crude-by-rail system has access to both the Gulf Coast market and the Cushing, Oklahoma, market. At the beginning of July 2012, EOG also began shipping a portion of its Eagle Ford Shale crude oil production to Gulf Coast sales points on the newly completed Enterprise Products Partners L.P. crude oil pipeline. In addition, EOG began supplying sand for a majority of its completion operations in several plays, primarily in Texas, from Wisconsin sand mines in 2012.

EOG's wholly-owned Canadian subsidiary, EOG Resources Canada Inc. (EOGRC), holds a 30% interest in both the planned liquefied natural gas export terminal to be located at Bish Cove, near the Port of Kitimat, north of Vancouver, British Columbia (Kitimat LNG Terminal) and the proposed Pacific Trail Pipelines (PTP) which is intended to link Western Canada's natural gas producing regions to the Kitimat LNG Terminal. An affiliate of Apache Corporation is the operator of both the PTP and the Kitimat LNG Terminal. Marketing efforts continue in order to support a final investment decision.

EOG's major producing areas in the United States and Canada are in Louisiana, New Mexico, North Dakota, Texas, Utah, Wyoming and western Canada.

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 and Modified U(b) Block, as well as the Pelican Field, have been developed and are producing natural gas and crude oil and condensate. Production from the Block 4(a) Toucan Field and the EMZ Area that began in the first quarter of 2012 is supplying natural gas under a contract with the National Gas Company of Trinidad and Tobago.

In the United Kingdom, EOG continues to make progress in field development for its East Irish Sea Conwy/Corfe crude oil discovery and its Central North Sea Columbus natural gas discovery. The field development plan for the Conwy/Corfe project was approved by the U.K. Department of Energy and Climate Change (DECC) in March 2012. The production platform was installed during the second quarter of 2012 and the pipelines are scheduled to be installed in the fourth quarter of 2012. EOG expects to begin processing facility installation in the first half of 2013. The Conwy development drilling program is expected to commence during the first quarter of 2013, with initial production expected in the second half of 2013. In the Central North Sea Columbus project, a revised field development plan was submitted to the DECC in the third quarter of 2012 with approval expected in the first quarter of 2013. The project participants are currently negotiating commercial agreements.

EOG's activity in Argentina is focused on the Vaca Muerta oil shale formation in the Neuquén Basin in Neuquén Province. During the first half of 2012, EOG participated in the drilling and completion of a vertical well in the Bajo del Toro Block. In the first quarter of 2012, EOG drilled a well to monitor future well completions in the Aguada del Chivato Block. During the first half of 2012, EOG drilled and completed a horizontal well in this block. Both the horizontal and vertical wells that were completed are under evaluation.

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 31% and 28% at September 30, 2012 and December 31, 2011, respectively. As used in this calculation, total capitalization represents the sum of total current and long-term debt and total stockholders' equity.

On September 10, 2012, EOG closed its sale of $1,250 million aggregate principal amount of 2.625% Senior Notes due 2023 (Notes). Interest on the Notes is payable semiannually in arrears on March 15 and September 15 of each year, beginning March 15, 2013. Net proceeds from the offering of approximately $1,234 million were used for general corporate purposes including the repayment of outstanding commercial paper borrowings and funding of capital expenditures.

EOG's total 2012 capital expenditures are estimated to total approximately $7.6 billion, excluding non-cash items. The majority of 2012 expenditures are focused on United States and Canada crude oil and liquids-rich gas drilling activity and, to a much lesser extent, natural gas drilling activity in the Haynesville, Marcellus and British Columbia Horn River Basin plays to hold acreage. EOG expects capital expenditures to be greater than cash flow from operating activities for 2012. In the first nine months of 2012, to cover the anticipated shortfall, EOG sold the Notes and received proceeds of $1,214 million from the sales of producing properties and acreage primarily in the Rocky Mountain area, Upper Gulf Coast area and Canada. 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 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, 2012 and 2011 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, 2012 vs. Three Months Ended September 30, 2011

Net Operating Revenues. During the third quarter of 2012, net operating revenues increased $69 million, or 2%, to $2,955 million from $2,886 million for the same period of 2011. Total wellhead revenues, which are revenues generated from sales of EOG's production of crude oil and condensate, natural gas liquids and natural gas, for the third quarter of 2012 increased $372 million, or 21%, to $2,109 million from $1,737 million for the same period of 2011. During the third quarter of 2012, EOG recognized net gains on the mark-to-market of financial commodity derivative contracts of $5 million compared to net gains of $358 million for the same period of 2011. Gathering, processing and marketing revenues, which are revenues generated from sales of third-party crude oil and condensate, natural gas liquids and natural gas as well as fees associated with gathering third-party natural gas, for the third quarter of 2012 increased $186 million, or 32%, to $764 million from $578 million for the same period of 2011. Gains on asset dispositions, net, of $67 million for the third quarter of 2012 primarily consist of gains on asset dispositions in the Rocky Mountain area.

Wellhead volume and price statistics for the three-month periods ended September 30, 2012 and 2011 were as follows:

	Three Months Ended September 30,	
	2012	**2011**
Crude Oil and Condensate Volumes (MBbld) [(1)]		
United States	161.3	108.9
Canada	6.7	6.8
Trinidad	1.2	3.1
Other International [(2)]	0.1	0.1
Total	169.3	118.9
Average Crude Oil and Condensate Prices ($/Bbl) [(3)]		
United States	$ 97.64	$ 87.22
Canada	86.09	90.54
Trinidad	90.84	89.70
Other International [(2)]	83.59	110.84
Composite	97.13	87.49
Natural Gas Liquids Volumes (MBbld) [(1)]		
United States	58.1	43.2
Canada	0.9	0.8
Total	59.0	44.0
Average Natural Gas Liquids Prices ($/Bbl) [(3)]		
United States	$ 30.95	$ 50.90
Canada	41.09	57.69
Composite	31.11	51.02
Natural Gas Volumes (MMcfd) [(1)]		
United States	1,022	1,122
Canada	94	123
Trinidad	387	330
Other International [(2)]	9	12
Total	1,512	1,587
Average Natural Gas Prices ($/Mcf) [(3)]		
United States	$ 2.61	$ 4.06
Canada	2.39	3.81
Trinidad	4.38	3.59
Other International [(2)]	5.67	5.54
Composite	3.07	3.95
Crude Oil Equivalent Volumes (MBoed) [(4)]		
United States	389.7	339.4
Canada	23.2	27.9
Trinidad	65.7	58.0
Other International [(2)]	1.7	2.0
Total	480.3	427.3
Total MMBoe [(4)]	44.2	39.3

(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 2012 increased $559 million, or 59%, to $1,512 million from $953 million for the same period of 2011, due to an increase of 50 MBbld, or 42%, in wellhead crude oil and condensate deliveries ($409 million) and a higher composite average wellhead crude oil and condensate price ($150 million). The increase in deliveries primarily reflects increased production in the Eagle Ford Shale and North Dakota Bakken. EOG's composite average wellhead crude oil and condensate price for the third quarter of 2012 increased 11% to $97.13 per barrel compared to $87.49 per barrel for the same period of 2011.

Natural gas liquids revenues for the third quarter of 2012 decreased $37 million, or 18%, to $170 million from $207 million for the same period of 2011, due to a lower composite average natural gas liquids price ($109 million), partially offset by an increase of 15 MBbld, or 34%, in natural gas liquids deliveries ($72 million). The increase in deliveries primarily reflects increased volumes in the Eagle Ford Shale, Permian Basin and Fort Worth Basin Barnett Shale. EOG's composite average natural gas liquids price for the third quarter of 2012 decreased 39% to $31.11 per barrel compared to $51.02 per barrel for the same period of 2011.

Wellhead natural gas revenues for the third quarter of 2012 decreased $150 million, or 26%, to $427 million from $577 million for the same period of 2011. The decrease was due to a lower composite average wellhead natural gas price ($123 million) and a decrease in natural gas deliveries ($27 million). EOG's composite average wellhead natural gas price for the third quarter of 2012 decreased 22% to $3.07 per thousand cubic feet (Mcf) compared to $3.95 per Mcf for the same period of 2011.

Natural gas deliveries for the third quarter of 2012 decreased 75 MMcfd, or 5%, to 1,512 MMcfd from 1,587 MMcfd for the same period of 2011. The decrease was primarily due to lower production in the United States (100 MMcfd) and Canada (29 MMcfd), partially offset by increased production in Trinidad (57 MMcfd). The decrease in the United States was attributable to asset sales and decreased production. The decrease in Canada was primarily due to decreased production in Alberta and the Horn River Basin area. The increase in Trinidad was primarily attributable to an increase in contractual deliveries.

During the third quarter of 2012, EOG recognized net gains on the mark-to-market of financial commodity derivative contracts of $5 million compared to net gains of $358 million for the same period of 2011. During the third quarter of 2012, the net cash inflow related to settled crude oil and natural gas derivative contracts was $249 million compared to the net cash inflow of $52 million for the same period of 2011.

Gathering, processing and marketing revenues represent sales of third-party crude oil and condensate, natural gas liquids and natural gas as well as fees associated with gathering third-party natural gas. For the three months and nine months ended September 30, 2012 and 2011, 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 2012, gathering, processing and marketing revenues and marketing costs increased, compared to the same period of 2011, primarily as a result of increased crude oil marketing activities. Gathering, processing and marketing revenues less marketing costs for the third quarter of 2012 totaled $9 million compared to $5 million for the same period of 2011.

Operating and Other Expenses. For the third quarter of 2012, operating expenses of $2,349 million were $413 million higher than the $1,936 million incurred in the third quarter of 2011. The following table presents the costs per barrel of oil equivalent (Boe) for the three-month periods ended September 30, 2012 and 2011:

	Three Months Ended September 30,	
	2012	**2011**
Lease and Well	$ 5.73	$ 6.34
Transportation Costs	3.72	2.77
Depreciation, Depletion and Amortization (DD&A) -		
Oil and Gas Properties	17.86	15.87
Other Property, Plant and Equipment	0.81	0.73
General and Administrative (G&A)	2.10	2.09
Interest Expense, Net	1.20	1.33
Total (1)	$ 31.42	$ 29.13

(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 and G&A for the three months ended September 30, 2012 compared to the same period of 2011 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 $253 million for the third quarter of 2012 increased $4 million from $249 million for the same prior year period primarily due to increased lease and well administrative expenses ($9 million) and increased operating and maintenance costs in the United States ($6 million) and Trinidad ($2 million), partially offset by decreased operating and maintenance costs in Canada ($4 million) and decreased workover expenditures in Canada ($4 million) and the United States ($3 million).

Transportation costs represent costs associated with the delivery of hydrocarbon products from the lease to a downstream point of sale. Transportation costs include 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, fuel costs, transportation fees and costs associated with crude-by-rail operations.

Transportation costs of $164 million for the third quarter of 2012 increased $55 million from $109 million for the same prior year period primarily due to increased transportation costs related to production from the Eagle Ford Shale ($29 million) and the Rocky Mountain area ($29 million), partially offset by decreased transportation costs related to production from the Fort Worth Basin Barnett Shale area ($4 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 field 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 and 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 calculated using the straight-line depreciation method over the useful lives of the assets.

DD&A expenses for the third quarter of 2012 increased $174 million to $826 million from $652 million for the same prior year period. DD&A expenses associated with oil and gas properties for the third quarter of 2012 were $167 million higher than the same prior year period primarily due to higher unit rates in the United States ($73 million), Trinidad ($15 million) and Canada ($5 million) and as a result of increased production in the United States ($80 million) and Trinidad ($3 million), partially offset by decreased production in Canada ($10 million).

DD&A expenses associated with other property, plant and equipment for the third quarter of 2012 were $7 million higher than the same prior year period primarily due to gathering and processing assets placed in service in the Eagle Ford Shale.

G&A expenses of $93 million for the third quarter of 2012 increased $11 million compared to the same prior year period primarily due to higher employee-related costs.

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 $7 million to $26 million for the third quarter of 2012 compared to $19 million for the same prior year period. The increase primarily reflects increased activities in the Eagle Ford Shale.

Impairments include amortization of unproved oil and gas property costs, as well as impairments of proved oil and gas properties and other property, plant and equipment. Unproved properties with individually significant acquisition costs are amortized over the lease term and analyzed on a property-by-property basis for any impairment in value. 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 producing field level to the unamortized capitalized cost of the asset. If the 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 natural gas assets held for sale, EOG utilizes accepted bids as the basis for determining fair value.

Impairments of $63 million for the third quarter of 2012 were $21 million lower than impairments for the same prior year period primarily due to decreased amortization of unproved property costs in the United States ($20 million) and decreased impairments of proved properties in Canada ($15 million), partially offset by increased impairments of other assets in the United States ($18 million). EOG recorded impairments of proved properties and other assets of $33 million and $32 million for the third quarter of 2012 and 2011, 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 2012 increased $21 million to $120 million (5.7% of wellhead revenues) compared to $99 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 ($16 million) and Canada ($3 million) and an increase in ad valorem/property taxes in the United States ($8 million), partially offset by decreased severance/production taxes in Trinidad ($5 million). The increase in severance/production taxes in the United States was primarily as a result of increased wellhead revenues.

Other income, net, was $8 million for the third quarter of 2012 compared to $1 million for the same prior year period. The increase of $7 million was primarily due to an increase in foreign currency transaction gains ($14 million), partially offset by an increase in deferred compensation expense ($5 million).

Income tax provision of $205 million for the third quarter of 2012 decreased $154 million compared to the same prior year period due primarily to lower pretax income. The third quarter 2012 net effective tax rate decreased to 37% from 40% in the same prior year period due to lower foreign taxes.

Nine Months Ended September 30, 2012 vs. Nine Months Ended September 30, 2011

Net Operating Revenues. During the first nine months of 2012, net operating revenues increased $1,318 million, or 18%, to $8,671 million from $7,353 million for the same period of 2011. Total wellhead revenues for the first nine months of 2012 increased $922 million, or 19%, to $5,871 million from $4,949 million for the same period of 2011. During the first nine months of 2012, EOG recognized net gains on the mark-to-market of financial commodity derivative contracts of $327 million compared to net gains of $481 million for the same period of 2011. Gathering, processing and marketing revenues for the first nine months of 2012 increased $732 million, or 50%, to $2,193 million from $1,461 million for the same period of 2011. Gains on asset dispositions, net, of $248 million for the first nine months of 2012 primarily consist of gains on asset dispositions in the Rocky Mountain area and Canada.

Wellhead volume and price statistics for the nine-month periods ended September 30, 2012 and 2011 were as follows:

	Nine Months Ended September 30, 2012	Nine Months Ended September 30, 2011
Crude Oil and Condensate Volumes (MBbld)		
United States	147.6	94.3
Canada	6.9	8.0
Trinidad	1.7	3.6
Other International	0.1	0.1
Total	156.3	106.0
Average Crude Oil and Condensate Prices ($/Bbl) [1]		
United States	$ 98.26	$ 91.40
Canada	86.25	92.76
Trinidad	93.85	91.56
Other International	90.34	98.77
Composite	97.68	91.52
Natural Gas Liquids Volumes (MBbld)		
United States	54.3	38.7
Canada	0.9	0.8
Total	55.2	39.5
Average Natural Gas Liquids Prices ($/Bbl)		
United States	$ 35.43	$ 49.85
Canada	44.61	54.36
Composite	35.58	49.93
Natural Gas Volumes (MMcfd)		
United States	1,051	1,123
Canada	98	135
Trinidad	393	354
Other International	10	13
Total	1,552	1,625
Average Natural Gas Prices ($/Mcf) [1]		
United States	$ 2.39	$ 4.13
Canada	2.35	3.88
Trinidad	3.60	3.42
Other International	5.70	5.60
Composite	2.71	3.97
Crude Oil Equivalent Volumes (MBoed)		
United States	377.2	320.3
Canada	24.1	31.2
Trinidad	67.1	62.7
Other International	1.8	2.2
Total	470.2	416.4
Total MMBoe	128.8	113.7

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

Wellhead crude oil and condensate revenues for the first nine months of 2012 increased $1,550 million, or 59%, to $4,199 million from $2,649 million for the same period of 2011, due to an increase of 50 MBbld, or 47%, in wellhead crude oil and condensate deliveries ($1,285 million) and a higher composite average wellhead crude oil and condensate price ($265 million). The increase in deliveries primarily reflects increased production in the Eagle Ford Shale and North Dakota Bakken. EOG's composite average wellhead crude oil and condensate price for the first nine months of 2012 increased 7% to $97.68 per barrel compared to $91.52 per barrel for the same period of 2011.

Natural gas liquids revenues for the first nine months of 2012 decreased $20 million, or 4%, to $519 million from $539 million for the same period of 2011, due to a lower composite average natural gas liquids price ($209 million), partially offset by an increase of 16 MBbld, or 40%, in natural gas liquids deliveries ($189 million). The increase in deliveries primarily reflects increased volumes in the Eagle Ford Shale and Fort Worth Basin Barnett Shale. EOG's composite average natural gas liquids price for the first nine months of 2012 decreased 29% to $35.58 per barrel compared to $49.93 per barrel for the same period of 2011.

Wellhead natural gas revenues for the first nine months of 2012 decreased $608 million, or 34%, to $1,153 million from $1,761 million for the same period of 2011. The decrease was due to a lower composite average wellhead natural gas price ($535 million) and decreased natural gas deliveries ($73 million). EOG's composite average wellhead natural gas price for the first nine months of 2012 decreased 32% to $2.71 per Mcf compared to $3.97 per Mcf for the same period of 2011.

Natural gas deliveries for the first nine months of 2012 decreased 73 MMcfd, or 4%, to 1,552 MMcfd from 1,625 MMcfd for the same period of 2011. The decrease was primarily due to decreased production in the United States (72 MMcfd) and Canada (37 MMcfd), partially offset by higher production in Trinidad (39 MMcfd). The decrease in the United States was attributable to asset sales and decreased production. The decrease in production in Canada was due to decreased production in Alberta and the Horn River Basin area. The increase in Trinidad was primarily attributable to an increase in contractual deliveries.

During the first nine months of 2012, EOG recognized net gains on the mark-to-market of financial commodity derivative contracts of $327 million compared to net gains of $481 million for the same period of 2011. During the first nine months of 2012, the net cash inflow related to settled crude oil and natural gas derivative contracts was $556 million compared to the net cash inflow of $84 million for the same period of 2011.

During the first nine months of 2012, gathering, processing and marketing revenues and marketing costs increased, compared to the same period of 2011, primarily as a result of increased crude oil marketing activities. Gathering, processing and marketing revenues less marketing costs for the first nine months of 2012 totaled $38 million compared to $34 million for the same period of 2011.

Operating and Other Expenses. For the first nine months of 2012, operating expenses of $6,813 million were $1,271 million higher than the $5,542 million incurred in the same period of 2011. The following table presents the costs per Boe for the nine-month periods ended September 30, 2012 and 2011:

	Nine Months Ended September 30,	
	2012	**2011**
Lease and Well	$ 5.96	$ 5.99
Transportation Costs	3.36	2.71
DD&A -		
Oil and Gas Properties	17.72	15.24
Other Property, Plant and Equipment	0.84	0.80
G&A	1.91	1.93
Interest Expense, Net	1.20	1.35
Total (1)	$ 30.99	$ 28.02

(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 and G&A for the nine months ended September 30, 2012 compared to the same period of 2011 are set forth below.

Lease and well expenses of $766 million for the first nine months of 2012 increased $85 million from $681 million for the same prior year period primarily due to increased operating and maintenance costs in the United States ($77 million) and Trinidad ($4 million) and increased lease and well administrative expenses ($18 million), partially offset by decreased workover expenditures in Canada ($5 million) and decreased operating and maintenance costs in Canada ($5 million).

Transportation costs of $432 million for the first nine months of 2012 increased $124 million from $308 million for the same prior year period primarily due to increased transportation costs related to production from the Eagle Ford Shale ($83 million), the Rocky Mountain area ($43 million) and the Upper Gulf Coast area ($7 million), partially offset by decreased transportation costs related to production from the Fort Worth Basin Barnett Shale area ($12 million).

DD&A expenses for the first nine months of 2012 increased $560 million to $2,383 million from $1,823 million for the same prior year period. DD&A expenses associated with oil and gas properties for the first nine months of 2012 were $544 million higher than the same prior year period primarily due to higher unit rates in the United States ($299 million), Canada ($22 million) and Trinidad ($13 million) and as a result of increased production in the United States ($250 million) and Trinidad ($7 million), partially offset by decreased production in Canada ($45 million) and favorable changes in the Canadian exchange rate ($4 million).

DD&A expenses associated with other property, plant and equipment for the first nine months of 2012 were $16 million higher than the same prior year period primarily due to gathering and processing assets placed in service in the Eagle Ford Shale.

G&A expenses of $245 million for the first nine months of 2012 increased $25 million compared to the same prior year period primarily due to higher employee-related costs.

Gathering and processing costs for the first nine months of 2012 increased $17 million to $72 million compared to the same prior year period primarily due to increased activities in the Eagle Ford Shale.

Impairments of $250 million for the first nine months of 2012 were $281 million lower than impairments for the same prior year period primarily due to decreased impairments of proved properties in Canada ($327 million) and decreased amortization of unproved property costs in the United States ($31 million) and Canada ($6 million), partially offset by increased impairments of proved properties and other assets in the United States ($83 million). EOG recorded impairments of proved properties and other assets of $148 million and $391 million for the first nine months of 2012 and 2011, respectively.

Taxes other than income for the first nine months of 2012 increased $51 million to $360 million (6.1% of wellhead revenues) from $309 million (6.2% 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 ($56 million) primarily as a result of increased wellhead revenues and a newly enacted fee imposed by the State of Pennsylvania on certain wells drilled in the state in 2012 and prior years and higher ad valorem/property taxes in the United States ($12 million). The increases are partially offset by a decrease in severance/production taxes in Trinidad ($15 million) and an increase in credits available to EOG in 2012 for Texas high-cost gas severance tax rate reductions ($5 million).

Other income, net, was $23 million for the first nine months of 2012 compared to $11 million for the same prior year period. The increase of $12 million was primarily due to foreign currency transaction gains realized in 2012 as compared to losses realized in 2011.

Income tax provision of $651 million for the first nine months of 2012 decreased $46 million compared to the same prior year period due primarily to a lower foreign tax provision. The net effective tax rate for the first nine months of 2012 decreased to 38% from 42% in the same prior year period primarily due to the absence of certain 2011 Canadian shallow natural gas impairments, which were tax effected at the lower Canadian statutory tax rate. The effective tax rate for the first nine months of 2012 exceeded the United States statutory tax rate (35%) primarily due to foreign losses in Canada (26% statutory tax rate).

Capital Resources and Liquidity

Cash Flow. The primary sources of cash for EOG during the nine months ended September 30, 2012 were funds generated from operations, net proceeds from the issuance of the Notes, proceeds from asset sales 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; and dividend payments to stockholders. During the first nine months of 2012, EOG's cash balance increased $497 million to $1,113 million from $616 million at December 31, 2011.

Net cash provided by operating activities of $4,010 million for the first nine months of 2012 increased $668 million compared to the same period of 2011 primarily reflecting an increase in wellhead revenues ($922 million) and a favorable change in net cash flow from the settlement of financial commodity derivative contracts ($472 million), partially offset by an increase in cash operating expenses ($289 million), unfavorable changes in working capital and other assets and liabilities ($251 million), an increase in net cash paid for income taxes ($108 million) and an increase in net cash paid for interest expense ($21 million).

Net cash used in investing activities of $4,678 million for the first nine months of 2012 increased by $672 million compared to the same period of 2011 due primarily to an increase in additions to oil and gas properties ($661 million) and a decrease in proceeds from sales of assets ($81 million), partially offset by favorable changes in working capital associated with investing activities ($46 million) and a decrease in additions to other property, plant and equipment ($25 million).

Net cash provided by financing activities of $1,161 million for the first nine months of 2012 included net proceeds from the issuance of the Notes ($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 the purchase of treasury stock in connection with stock compensation plans ($45 million). Net cash provided by financing activities of $1,270 million for the first nine months of 2011 included net proceeds from the sale of common stock ($1,338 million) and proceeds from stock options exercised and employee stock purchase plan activity ($27 million). Cash used in financing activities for the first nine months of 2011 included cash dividend payments ($124 million) and the purchase of treasury stock in connection with stock compensation plans ($21 million).

Total Expenditures. For the year 2012, EOG's budget for exploration and development and other property, plant and equipment expenditures is approximately $7.6 billion, excluding non-cash items. The table below sets out components of total expenditures for the nine-month periods ended September 30, 2012 and 2011 (in millions):

	Nine Months Ended September 30,	
	2012	**2011**
Expenditure Category		
Capital		
Drilling and Facilities	$ 4,894	$ 4,377
Leasehold Acquisitions	382	192
Property Acquisitions	-	4
Capitalized Interest	37	44
Subtotal	5,313	4,617
Exploration Costs	137	141
Dry Hole Costs	13	47
Exploration and Development Expenditures	5,463	4,805
Asset Retirement Costs	62	111
Total Exploration and Development Expenditures	5,525	4,916
Other Property, Plant and Equipment	543 (1)	502
Total Expenditures	$ 6,068	$ 5,418

(1) Includes non-cash additions of $66 million in connection with a capital lease transaction in the Eagle Ford Shale (see Note 10 to Consolidated Financial Statements).

Exploration and development expenditures of $5,463 million for the first nine months of 2012 were $658 million higher than the same period of 2011 due primarily to increased drilling and facilities expenditures in the United States ($495 million), the United Kingdom ($62 million) and Argentina ($42 million); increased leasehold acquisition expenditures in the United States ($163 million) and Canada ($26 million); and increased exploration administrative expenses in the United States ($6 million). These increases were partially offset by decreased drilling and facilities expenditures in Trinidad ($80 million), decreased dry hole costs in the United States ($25 million), decreased exploration geological and geophysical expenditures in the United States ($8 million), decreased capitalized interest in the United States ($7 million), decreased property acquisition expenditures in the United States ($4 million) and favorable changes in the foreign currency exchange rate in Canada ($4 million). 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 exploration and development expenditures for the first nine months of 2011 of $4,805 million consist of $4,335 million in development, $422 million in exploration, $44 million in capitalized interest and $4 million in property acquisitions.

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, 2011, filed on February 24, 2012, 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, collar, option 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 Gains on Mark-to-Market Commodity Derivative Contracts in the Consolidated Statements of Income and Comprehensive Income. The related cash flow impact is reflected as 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 estimated fair value of EOG's crude oil and natural gas derivative contracts (options/swaptions) was reflected on the Consolidated Balance Sheets at September 30, 2012 as a net asset of $245 million. Presented below is a comprehensive summary of EOG's crude oil derivative contracts at November 5, 2012, with notional volumes expressed in barrels per day (Bbld) and prices expressed in dollars per barrel ($/Bbl).

Crude Oil Derivative Contracts		
	Volume [(1)] (Bbld)	Weighted Average Price ($/Bbl)
2012		
January 1, 2012 through February 29, 2012 (closed)	34,000	$104.95
March 1, 2012 through June 30, 2012 (closed)	52,000	105.80
July 1, 2012 through August 31, 2012 (closed)	50,000	106.90
September 2012 (closed)	32,000	106.61
October 2012 (closed)	42,000	105.19
November 1, 2012 through December 31, 2012	42,000	105.19
2013		
January 1, 2013 through June 30, 2013	98,000	$ 99.39
July 1, 2013 through December 31, 2013	68,000	99.45

(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 25,000 Bbld are exercisable on December 31, 2012. If the counterparties exercise all such options, the notional volume of EOG's existing crude oil derivative contracts will increase by 25,000 Bbld at an average price of $106.27 per barrel for the period January 1, 2013 through June 30, 2013. Options covering a notional volume of 59,000 Bbld are exercisable on June 28, 2013. If the counterparties exercise all such options, the notional volume of EOG's existing crude oil derivative contracts will increase by 59,000 Bbld at an average price of $100.45 per barrel for the period July 1, 2013 through December 31, 2013. Options covering a notional volume of 29,000 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 29,000 Bbld at an average price of $101.69 per barrel for the period from January 1, 2014 through June 30, 2014.

Presented below is a comprehensive summary of EOG's natural gas derivative contracts at November 5, 2012, 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)
2012 (1)		
January 1, 2012 through November 30, 2012 (closed)	525,000	$5.44
December 2012	525,000	5.44
2013 (2)		
January 1, 2013 through December 31, 2013	150,000	$4.79
2014 (3)		

(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. If the counterparties exercise all such options, the notional volume of EOG's existing natural gas derivative contracts will increase by 425,000 MMBtud at an average price of $5.44 per MMBtu for December 2012.

(2) 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. 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 of 2013.

(3) In July 2012, EOG settled its natural gas financial price swap contracts for the period January 1, 2014 through December 31, 2014 and received proceeds of $36.6 million. In connection with these contracts, the counterparties retain an option of entering into derivative contracts at future dates. 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 150,000 MMbtud at an average price of $4.79 per MMBtu for each month of 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 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" 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 and unknown 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, natural gas liquids, 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;
- 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 developments around the world, 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; and
- the other factors described under Item 1A, "Risk Factors," on pages 15 through 23 of EOG's Annual Report on Form 10-K for the year ended December 31, 2011.

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, 2011, filed on February 24, 2012 (EOG's 2011 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 2011 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 submits under the Exchange Act is (i) recorded, processed, summarized and reported within the time periods specified in the 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, 2012 – July 31, 2012	44,252	$ 93.10	-	6,386,200
August 1, 2012 – August 31, 2012	6,491	108.19	-	6,386,200
September 1, 2012 – September 30, 2012	166,433	113.46	-	6,386,200
Total	217,176	109.15	-	

(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 2012, 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
4.1	-	Officers' Certificate Establishing 2.625% Senior Notes due 2023, dated September 10, 2012 (incorporated by reference to Exhibit 4.2 to EOG's Current Report on Form 8-K, filed September 11, 2012).
4.2	-	Form of Global Note with respect to the 2.625% Senior Notes due 2023 of EOG (incorporated by reference to Exhibit 4.3 to EOG's Current Report on Form 8-K, filed September 11, 2012).
* 10.1	-	Third Amendment to EOG Resources, Inc. 2008 Omnibus Equity Compensation Plan, dated effective as of September 26, 2012.
10.2	-	Form of Performance Unit Award Agreement for EOG Resources, Inc. 2008 Omnibus Equity Compensation Plan (incorporated by reference to Exhibit 10.4 to EOG's Current Report on Form 8-K, filed October 1, 2012).
10.3	-	Form of Performance Stock Award Agreement for EOG Resources, Inc. 2008 Omnibus Equity Compensation Plan (incorporated by reference to Exhibit 10.5 to EOG's Current Report on Form 8-K, filed October 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.
* **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, 2012 and 2011 and Nine Months Ended September 30, 2012 and 2011, (ii) the Consolidated Balance Sheets - September 30, 2012 and December 31, 2011, (iii) the Consolidated Statements of Cash Flows - Nine Months Ended September 30, 2012 and 2011 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 5, 2012

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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