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, 2010

or

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

Commission File Number: 1-9743

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	254,015,745 (as of October 28, 2010)

EOG RESOURCES, INC.

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PART I. FINANCIAL INFORMATION

ITEM 1. FINANCIAL STATEMENTS
EOG RESOURCES, INC.
CONSOLIDATED STATEMENTS OF INCOME
(In Thousands, Except Per Share Data)
(Unaudited)

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2010	**2009**	**2010**	**2009**
Net Operating Revenues				
Natural Gas	$ 602,242	$ 450,304	$ 1,832,578	$ 1,477,926
Crude Oil, Condensate and Natural Gas Liquids	613,850	398,806	1,683,088	886,268
Gains on Mark-to-Market Commodity Derivative Contracts	60,998	20,877	105,816	405,830
Gathering, Processing and Marketing	233,971	134,553	601,790	249,679
Gains (Losses) on Property Dispositions	64,809	(232)	72,441	510
Other, Net	6,205	2,541	15,023	5,884
Total	1,582,075	1,006,849	4,310,736	3,026,097
Operating Expenses				
Lease and Well	180,921	142,183	507,647	422,288
Transportation Costs	103,262	70,971	286,318	205,844
Gathering and Processing Costs	18,472	13,318	47,353	44,552
Exploration Costs	47,307	44,910	148,635	128,840
Dry Hole Costs	2,700	3,016	45,095	39,653
Impairments	352,908	69,404	502,865	181,921
Marketing Costs	231,758	131,816	591,735	237,819
Depreciation, Depletion and Amortization	500,888	385,330	1,398,137	1,150,251
General and Administrative	81,310	62,775	206,470	179,481
Taxes Other Than Income	74,244	47,823	227,773	118,715
Total	1,593,770	971,546	3,962,028	2,709,364
Operating Income (Loss)	(11,695)	35,303	348,708	316,733
Other Income (Expense), Net	5,772	(339)	7,910	2,637
Income (Loss) Before Interest Expense and Income Taxes	(5,923)	34,964	356,618	319,370
Interest Expense, Net	32,890	30,407	88,215	73,594
Income (Loss) Before Income Taxes	(38,813)	4,557	268,403	245,776
Income Tax Provision	32,093	361	161,422	99,576
Net Income (Loss)	$ (70,906)	$ 4,196	$ 106,981	$ 146,200
Net Income (Loss) Per Share				
Basic	$ (0.28)	$ 0.02	$ 0.43	$ 0.59
Diluted	$ (0.28)	$ 0.02	$ 0.42	$ 0.58
Dividends Declared per Common Share	$ 0.155	$ 0.145	$ 0.465	$ 0.435
Average Number of Common Shares				
Basic	251,015	249,535	250,719	248,647
Diluted	251,015	252,422	254,444	251,288

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, 2010	December 31, 2009
ASSETS		
Current Assets		
Cash and Cash Equivalents	$ 27,832	$ 685,751
Accounts Receivable, Net	897,732	771,417
Inventories	381,263	261,723
Assets from Price Risk Management Activities	60,728	20,915
Income Taxes Receivable	89,357	37,009
Other	77,533	62,726
Total	1,534,445	1,839,541
Property, Plant and Equipment		
Oil and Gas Properties (Successful Efforts Method)	28,208,613	24,614,311
Other Property, Plant and Equipment	1,598,453	1,350,132
Total Property, Plant and Equipment	29,807,066	25,964,443
Less: Accumulated Depreciation, Depletion and Amortization	(11,557,256)	(9,825,218)
Total Property, Plant and Equipment, Net	18,249,810	16,139,225
Other Assets	160,604	139,901
Total Assets	$ 19,944,859	$ 18,118,667
LIABILITIES AND STOCKHOLDERS' EQUITY		
Current Liabilities		
Accounts Payable	$ 1,541,268	$ 979,139
Accrued Taxes Payable	114,763	92,858
Dividends Payable	38,946	36,286
Liabilities from Price Risk Management Activities	29,144	27,218
Deferred Income Taxes	45,367	35,414
Current Portion of Long-Term Debt	-	37,000
Other	168,812	137,645
Total	1,938,300	1,345,560
Long-Term Debt	3,768,638	2,760,000
Other Liabilities	695,855	632,652
Deferred Income Taxes	3,423,942	3,382,413
Commitments and Contingencies (Note 9)		
Stockholders' Equity		
Common Stock, $0.01 Par, 640,000,000 Shares Authorized and 253,985,680 Shares Issued at September 30, 2010 and 252,627,177 Shares Issued at December 31, 2009	202,540	202,526
Additional Paid in Capital	695,046	596,702
Accumulated Other Comprehensive Income	375,847	339,720
Retained Earnings	8,855,869	8,866,747
Common Stock Held in Treasury, 145,613 Shares at September 30, 2010 and 118,525 Shares at December 31, 2009	(11,178)	(7,653)
Total Stockholders' Equity	10,118,124	9,998,042
Total Liabilities and Stockholders' Equity	$ 19,944,859	$ 18,118,667

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, 2010	Nine Months Ended September 30, 2009
Cash Flows from Operating Activities		
Reconciliation of Net Income to Net Cash Provided by Operating Activities:		
Net Income	$ 106,981	$ 146,200
Items Not Requiring (Providing) Cash		
Depreciation, Depletion and Amortization	1,398,137	1,150,251
Impairments	502,865	181,921
Stock-Based Compensation Expenses	81,700	74,532
Deferred Income Taxes	53,067	39,793
Gains on Property Dispositions, Net	(72,441)	(510)
Other, Net	(2,317)	3,248
Dry Hole Costs	45,095	39,653
Mark-to-Market Commodity Derivative Contracts		
Total Gains	(105,816)	(405,830)
Realized Gains	25,180	986,980
Excess Tax Benefits from Stock-Based Compensation	-	(34,052)
Other, Net	13,354	9,385
Changes in Components of Working Capital and Other Assets and Liabilities		
Accounts Receivable	(124,813)	119,099
Inventories	(134,181)	(23,592)
Accounts Payable	527,418	(361,698)
Accrued Taxes Payable	(40,104)	16,097
Other Assets	(16,051)	(4,255)
Other Liabilities	44,348	9,357
Changes in Components of Working Capital Associated with Investing and Financing Activities	(216,695)	147,097
Net Cash Provided by Operating Activities	2,085,727	2,093,676
Investing Cash Flows		
Additions to Oil and Gas Properties	(3,740,883)	(2,267,884)
Additions to Other Property, Plant and Equipment	(223,072)	(240,614)
Proceeds from Sales of Assets	126,371	2,515
Changes in Components of Working Capital Associated with Investing Activities	216,546	(146,783)
Other, Net	(4,206)	1,405
Net Cash Used in Investing Activities	(3,625,244)	(2,651,361)
Financing Cash Flows		
Net Commercial Paper Borrowings	33,700	-
Long-Term Debt Borrowings	991,395	900,000
Long-Term Debt Repayments	(37,000)	-
Dividends Paid	(114,277)	(105,989)
Excess Tax Benefits from Stock-Based Compensation	-	34,052
Treasury Stock Purchased	(10,298)	(9,888)
Proceeds from Stock Options Exercised and Employee Stock Purchase Plan	24,527	13,691
Debt Issuance Costs	(6,469)	(8,887)
Other, Net	149	(314)
Net Cash Provided by Financing Activities	881,727	822,665
Effect of Exchange Rate Changes on Cash	(129)	12,220
(Decrease) Increase in Cash and Cash Equivalents	(657,919)	277,200
Cash and Cash Equivalents at Beginning of Period	685,751	331,311
Cash and Cash Equivalents at End of Period	$ 27,832	$ 608,511

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, 2009, filed with the SEC on February 25, 2010 (EOG's 2009 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, 2010 are not necessarily indicative of the results to be expected for the full year.

EOG has determined that there are no subsequent events which require recognition or disclosure in these consolidated financial statements except as disclosed herein.

Recently Issued Accounting Standards and Developments. In January 2010, the Financial Accounting Standards Board (FASB) issued Accounting Standards Update (ASU) 2010-06, "Improving Disclosures About Fair Value Measurements" (ASU 2010-06), which amends the Fair Value Measurements and Disclosures Topic of the Accounting Standards Codification (ASC) (ASC Topic 820). Among other provisions, ASC Topic 820 establishes a fair value hierarchy that prioritizes the relative reliability of inputs used in fair value measurements. The hierarchy gives highest priority to Level 1 inputs that represent unadjusted quoted market prices in active markets for identical assets and liabilities that the reporting entity has the ability to access at the measurement date. Level 2 inputs are directly or indirectly observable inputs other than quoted prices included within Level 1. Level 3 inputs are unobservable inputs and have the lowest priority in the hierarchy. This amendment requires new disclosures on the value of, and the reason for, transfers in and out of Levels 1 and 2 of the fair value hierarchy and additional disclosures about purchases, sales, issuances and settlements within Level 3 fair value measurements. ASU 2010-06 also clarifies existing disclosure requirements on levels of disaggregation and about inputs and valuation techniques. ASU 2010-06 is effective for interim and annual reporting periods beginning after December 15, 2009, except for the requirement to provide additional disclosures regarding Level 3 measurements which will be effective for interim and annual reporting periods beginning after December 15, 2010. See Note 12.

2. Stock-Based Compensation

As more fully discussed in Note 6 to the Consolidated Financial Statements included in EOG's 2009 Annual Report, EOG maintains various stock-based compensation plans. Stock-based compensation expense is included in the Consolidated Statements of Income based upon job functions of the employees receiving the grants as follows (in millions):

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2010	2009	2010	2009
Lease and Well	$ 8.0	$ 6.3	$ 20.3	$ 17.7
Gathering and Processing Costs	0.1	-	0.4	-
Exploration Costs	7.3	5.1	18.1	15.2
General and Administrative	21.3	14.6	42.9	41.6
Total	$ 36.7	$ 26.0	$ 81.7	$ 74.5

At the 2010 Annual Meeting of Stockholders in April 2010 (2010 Annual Meeting), an amendment to the EOG Resources, Inc. 2008 Omnibus Equity Compensation Plan, as amended (2008 Plan), was approved, pursuant to which the number of shares of common stock available for future grants of stock options, stock-settled stock appreciation rights (SARs), restricted stock, restricted stock units and other stock-based awards under the 2008 Plan was increased by an additional 6.9 million shares, to an aggregate maximum of 12.9 million shares plus shares underlying forfeited or cancelled grants under the prior stock plans. At September 30, 2010, approximately 7.0 million common shares remained available for grant under the 2008 Plan. Effective with the adoption of the 2008 Plan, EOG's policy is to issue shares related to the 2008 Plan from previously authorized unissued shares.

Stock Options and Stock Appreciation Rights and Employee Stock Purchase Plan. The fair value of all Employee Stock Purchase Plan (ESPP) grants is estimated using the Black-Scholes-Merton model. Certain of EOG's stock options granted in 2005 contain a feature that limits the potential gain that can be realized by requiring vested options to be exercised if the market price of EOG's common stock reaches 200% of the grant price for five consecutive trading days (Capped Option). EOG may or may not issue Capped Options in the future. The fair value of each Capped Option grant was estimated using a Monte Carlo simulation. Effective May 2005, the fair value of stock option grants not containing the Capped Option feature and SAR grants is estimated using the Hull-White II binomial option pricing model. Stock-based compensation expense related to stock option, SAR and ESPP grants totaled $12.6 million and $10.3 million during the three months ended September 30, 2010 and 2009, respectively, and $30.4 million and $29.4 million during the nine months ended September 30, 2010 and 2009, respectively.

At the 2010 Annual Meeting, an amendment to the ESPP was approved to increase the shares available for grant by 1.0 million shares. The ESPP was originally approved by EOG's stockholders in 2001, and would have expired on July 1, 2011. The amendment also extended the term of the ESPP to December 31, 2019, unless terminated earlier by its terms or by EOG. EOG had previously suspended the ESPP, effective for the July 1, 2009 to December 31, 2009 offering period, due to an insufficient number of shares then remaining available under the ESPP. As a result of stockholder approval at the 2010 Annual Meeting of the above-referenced amendment to the ESPP to increase the shares available under the ESPP, EOG resumed the ESPP for the January 1, 2010 to June 30, 2010 offering period.

Weighted average fair values and valuation assumptions used to value stock option, SAR and ESPP grants during the nine-month periods ended September 30, 2010 and 2009 are as follows:

	Stock Options/SARs		ESPP	
	Nine Months Ended September 30,		Nine Months Ended September 30,	
	2010	2009	2010	2009
Weighted Average Fair Value of Grants	$ 32.10	$ 30.11	$ 25.42	$ 25.78
Expected Volatility	39.74%	41.92%	38.18%	78.89%
Risk-Free Interest Rate	0.87%	1.42%	0.18%	0.25%
Dividend Yield	0.7%	0.7%	0.7%	1.0%
Expected Life	5.5 yrs	5.5 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 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 the stock option and SAR transactions for the nine-month periods ended September 30, 2010 and 2009 (stock options and SARs in thousands):

	Nine Months Ended September 30, 2010		Nine Months Ended September 30, 2009	
	Number of Stock Options/SARs	Weighted Average Grant Price	Number of Stock Options/SARs	Weighted Average Grant Price
Outstanding at January 1	8,335	$ 57.08	7,802	$ 52.56
Granted	1,420	93.02	1,251	80.87
Exercised (1)	(924)	40.11	(387)	41.67
Forfeited	(80)	80.12	(87)	73.85
Outstanding at September 30 (2)	8,751	64.49	8,579	56.96
Vested or Expected to Vest (3)	8,221	64.01	8,336	56.28
Exercisable at September 30 (4)	5,632	51.79	5,603	44.69

(1) The total intrinsic value of stock options/SARs exercised for the nine months ended September 30, 2010 and 2009 was $58 million and $12 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, 2010 and 2009 was $252 million and $236 million, respectively. At September 30, 2010 and 2009, the weighted average remaining contractual life was 4.1 years and 4.3 years, respectively.

(3) The total intrinsic value of stock options/SARs vested or expected to vest at September 30, 2010 and 2009 was $241 million and $235 million, respectively. At September 30, 2010 and 2009, the weighted average remaining contractual life was 4.1 years and 4.3 years, respectively.

(4) The total intrinsic value of stock options/SARs exercisable at September 30, 2010 and 2009 was $233 million and $220 million, respectively. At September 30, 2010 and 2009, the weighted average remaining contractual life was 3.0 years and 3.5 years, respectively.

At September 30, 2010, unrecognized compensation expense related to non-vested stock option, SAR and ESPP grants totaled $95.9 million. This unrecognized expense will be amortized on a straight-line basis over a weighted average period of 3.0 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 $24.1 million and $15.7 million for the three months ended September 30, 2010 and 2009, respectively, and $51.3 million and $45.1 million for the nine months ended September 30, 2010 and 2009, respectively.

The following table sets forth the restricted stock and restricted stock unit transactions for the nine-month periods ended September 30, 2010 and 2009 (shares and units in thousands):

	Nine Months Ended September 30, 2010		Nine Months Ended September 30, 2009	
	Number of Shares and Units	Weighted Average Grant Date Fair Value	Number of Shares and Units	Weighted Average Grant Date Fair Value
Outstanding at January 1	3,636	$ 73.69	3,048	$ 70.24
Granted	840	93.36	1,184	62.88
Released [1]	(308)	53.99	(500)	28.16
Forfeited	(57)	77.71	(47)	78.06
Outstanding at September 30 [2]	4,111	79.13	3,685	73.49

(1) The total intrinsic value of restricted stock and restricted stock units released for the nine months ended September 30, 2010 and 2009 was $30 million and $32 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, 2010 and 2009 was $382 million and $308 million, respectively.

At September 30, 2010, unrecognized compensation expense related to restricted stock and restricted stock units totaled $161 million. Such unrecognized expense will be recognized on a straight-line basis over a weighted average period of 2.9 years.

3. Net Income (Loss) Per Share

The following table sets forth the computation of Net Income (Loss) Per Share for the three-month and nine-month periods ended September 30, 2010 and 2009 (in thousands, except per share data). For the three-month period ending September 30, 2010, the same number of shares was used in the calculation of both basic and diluted earnings per share as a result of the net loss during the period.

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2010	2009	2010	2009
Numerator for Basic and Diluted Earnings Per Share -				
Net Income (Loss)	$ (70,906)	$ 4,196	$ 106,981	$ 146,200
Denominator for Basic Earnings Per Share -				
Weighted Average Shares	251,015	249,535	250,719	248,647
Potential Dilutive Common Shares -				
Stock Options/SARs	-	1,718	2,059	1,558
Restricted Stock and Restricted Stock Units	-	1,169	1,666	1,083
Denominator for Diluted Earnings Per Share -				
Adjusted Diluted Weighted Average Shares	251,015	252,422	254,444	251,288
Net Income (Loss) Per Share				
Basic	$ (0.28)	$ 0.02	$ 0.43	$ 0.59
Diluted	$ (0.28)	$ 0.02	$ 0.42	$ 0.58

The diluted earnings per share calculation excludes stock options, SARs and restricted stock and restricted stock units that were anti-dilutive. The excluded stock options and SARs totaled 7.9 million and 2.4 million for the three months ended September 30, 2010 and 2009, respectively, and 0.3 million and 2.5 million for the nine months ended September 30, 2010 and 2009, respectively. For the three months ended September 30, 2010, 4.1 million shares of restricted stock and restricted stock units were excluded.

4. Supplemental Cash Flow Information

Net cash paid for interest and income taxes was as follows for the nine-month periods ended September 30, 2010 and 2009 (in thousands):

	Nine Months Ended September 30,	
	2010	2009
Interest (1)	$ 71,177	$ 54,179
Income Taxes, Net of Refunds Received	$ 187,484	$ 45,823

(1) Net of capitalized interest of $57 million and $38 million for the nine months ended September 30, 2010 and 2009, respectively. Capitalized interest totaled $20 million and $13 million for the three months ended September 30, 2010 and 2009, respectively.

Non-cash investing activities for the nine months ended September 30, 2010 included non-cash additions of $3 million to EOG's oil and gas properties in connection with contingent consideration related to EOG's acquisition of certain unproved properties (see Note 14).

5. Comprehensive Income (Loss)

The following table presents the components of EOG's comprehensive income (loss) for the three-month and nine-month periods ended September 30, 2010 and 2009 (in thousands):

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2010	2009	2010	2009
Comprehensive Income (Loss)				
Net Income (Loss)	$ (70,906)	$ 4,196	$ 106,981	$ 146,200
Other Comprehensive Income (Loss)				
Foreign Currency Translation Adjustments	61,687	161,044	32,599	260,007
Foreign Currency Swap Transaction	(666)	504	4,724	5,470
Income Tax Related to Foreign Currency Swap Transaction	170	(446)	(1,273)	(1,704)
Defined Benefit Pension and Postretirement Plans	40	34	120	104
Income Tax Related to Defined Benefit Pension and Postretirement Plans	(15)	(12)	(43)	(37)
Total	$ (9,690)	$ 165,320	$ 143,108	$ 410,040

6. Segment Information

Selected financial information by reportable segment is presented below for the three-month and nine-month periods ended September 30, 2010 and 2009 (in thousands):

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2010	2009	2010	2009
Net Operating Revenues				
United States	$ 1,359,896	$ 849,338	$ 3,603,758	$ 2,571,956
Canada	103,587	92,678	357,186	283,722
Trinidad	110,904	60,353	328,900	151,765
Other International (1)	7,688	4,480	20,892	18,654
Total	$ 1,582,075	$ 1,006,849	$ 4,310,736	$ 3,026,097
Operating Income (Loss)				
United States	$ 252,871	$ 26,971	$ 562,194	$ 282,601
Canada	(330,985)	(18,883)	(386,205)	(27,281)
Trinidad	76,028	38,370	222,997	89,640
Other International (1)	(9,609)	(11,155)	(50,278)	(28,227)
Total	(11,695)	35,303	348,708	316,733
Reconciling Items				
Other Income (Expense), Net	5,772	(339)	7,910	2,637
Interest Expense, Net	32,890	30,407	88,215	73,594
Income (Loss) Before Income Taxes	$ (38,813)	$ 4,557	$ 268,403	$ 245,776

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

Total assets by reportable segment are presented below at September 30, 2010 and December 31, 2009 (in thousands):

	At September 30, 2010	At December 31, 2009
Total Assets		
United States	$ 16,321,612	$ 14,108,129
Canada	2,683,289	2,888,949
Trinidad	776,908	813,901
Other International [1]	163,050	307,688
Total	$ 19,944,859	$ 18,118,667

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

7. 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, 2010 and 2009 (in thousands):

	Nine Months Ended September 30, 2010	Nine Months Ended September 30, 2009
Carrying Amount at Beginning of Period	$ 456,484	$ 368,159
Liabilities Incurred	27,439	38,817
Liabilities Settled	(21,653)	(13,701)
Accretion	19,105	16,285
Revisions [1]	53,824	13,827
Foreign Currency Translations	1,980	10,462
Carrying Amount at End of Period	$ 537,179	$ 433,849
Current Portion	$ 28,767	$ 22,923
Noncurrent Portion	$ 508,412	$ 410,926

(1) Revisions to asset retirement obligations primarily reflect changes in abandonment cost estimates.

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.

8. Suspended Well Costs

EOG's net changes in suspended well costs for the nine-month period ended September 30, 2010 are presented below (in thousands):

		Nine Months Ended September 30, 2010
Balance at December 31, 2009	$	118,459
Additions Pending the Determination of Proved Reserves		104,859
Reclassifications to Proved Properties		(64,672)
Charged to Dry Hole Costs		(5,379)
Foreign Currency Translations		(49)
Balance at September 30, 2010	$	153,218

The following table provides an aging of suspended well costs at September 30, 2010 (in thousands, except well count):

		At September 30, 2010	
Capitalized exploratory well costs that have been capitalized for a period less than one year	$	85,949	
Capitalized exploratory well costs that have been capitalized for a period greater than one year		67,269	(1)
Total	$	153,218	
Number of exploratory wells that have been capitalized for a period greater than one year		5	

(1) Consists of costs related to two shale projects in British Columbia, Canada (B.C.) ($32 million), an outside operated, offshore Central North Sea project in the United Kingdom (U.K.) ($22 million), an East Irish Sea project in the U.K. ($9 million) and a well in the Sichuan Basin, Sichuan Province, The People's Republic of China ($4 million). In the B.C. shale projects, EOG is currently evaluating additional well data and infrastructure alternatives for delivery of product and expects to complete its evaluations by the end of 2010. In the Central North Sea project, EOG is currently evaluating an export route and negotiating commercial terms for transport of production from the project. The operator expects to submit a revised field development plan to the U.K. Department of Energy and Climate Change during the fourth quarter of 2010 and anticipates approval in the first quarter of 2011. In the East Irish Sea project, EOG is currently preparing a field development plan that it anticipates submitting to the U.K. Department of Energy and Climate Change during the fourth quarter of 2010. The evaluation of the Sichuan Basin project is expected to be completed in early 2011.

9. 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 with certainty, 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.

10. Pension Benefits

EOG has a non-contributory defined contribution pension plan and a matched defined contribution savings plan in place for most of its employees in the United States. For the nine months ended September 30, 2010 and 2009, EOG's total costs recognized for these pension plans were $16.7 million and $15.2 million, respectively.

In addition, as more fully discussed in Note 6 to Consolidated Financial Statements included in EOG's 2009 Annual Report, EOG's Canadian, Trinidadian and United Kingdom subsidiaries maintain various pension and savings plans for most of their respective employees. For the nine months ended September 30, 2010 and 2009, combined contributions to these plans were $2.2 million and $1.8 million, respectively.

11. Long-Term Debt

Long-Term Debt. EOG utilizes commercial paper and short-term borrowings from uncommitted credit facilities, bearing market interest rates, for various corporate financing purposes. At September 30, 2010, EOG had $34 million of outstanding borrowings from commercial paper and no outstanding borrowings from uncommitted credit facilities. The average commercial paper borrowings outstanding for the nine months ended September 30, 2010 was $112 million. The weighted average interest rates for commercial paper and uncommitted credit facility borrowings for the nine months ended September 30, 2010 were 0.34% and 0.68%, respectively. Commercial paper outstanding at September 30, 2010 was classified as long-term debt based upon EOG's intent and ability to replace such amounts with other long-term debt.

On May 20, 2010, EOG completed its public offering of $500 million aggregate principal amount of 2.95% Senior Notes due 2015 and $500 million aggregate principal amount of 4.40% Senior Notes due 2020 (together, Notes). Interest on the Notes is payable semi-annually in arrears on June 1 and December 1 of each year beginning December 1, 2010. Net proceeds from the Notes offering of approximately $990 million were used for general corporate purposes, including repayment of outstanding commercial paper borrowings.

EOG currently has two $1.0 billion unsecured Revolving Credit Agreements with domestic and foreign lenders. At September 30, 2010, there were no borrowings or letters of credit outstanding under either of these agreements. The first $1.0 billion unsecured Revolving Credit Agreement (2005 Agreement) matures on June 28, 2012. Advances under the 2005 Agreement accrue interest based, at EOG's option, on either the London InterBank Offering Rate plus an applicable margin (Eurodollar rate) or the base rate of the 2005 Agreement's administrative agent. At September 30, 2010, the Eurodollar rate and applicable base rate, had there been any amounts borrowed under the 2005 Agreement, would have been 0.45% and 3.25%, respectively.

On September 10, 2010, EOG entered into the second $1.0 billion unsecured Revolving Credit Agreement (2010 Agreement). The 2010 Agreement matures on September 10, 2013. Advances under the 2010 Agreement accrue interest based, at EOG's option, on either the Eurodollar rate or the base rate (as defined in the 2010 Agreement) plus an applicable margin. At September 30, 2010, the Eurodollar rate and applicable base rate, had there been any amounts borrowed under the 2010 Agreement, would have been 1.83% and 3.83%, respectively. The 2010 Agreement and the 2005 Agreement each contain representations, warranties, covenants and events of default that are customary for investment grade, senior unsecured commercial bank credit agreements, including a financial covenant for the maintenance of a total debt-to-total capitalization ratio of no greater than 65%.

On May 12, 2010, EOG Resources Trinidad Limited, a wholly owned foreign subsidiary of EOG, repaid at maturity the remaining $37 million outstanding balance of, and cancelled, its $75 million Revolving Credit Agreement.

Fair Value of Debt. At September 30, 2010 and December 31, 2009, EOG had outstanding $3,794 million and $2,797 million, respectively, aggregate principal amount of debt, which had estimated fair values of approximately $4,329 million and $3,056 million, respectively. The estimated fair value of debt was based upon quoted market prices and, where such quotes were not available, upon interest rates available to EOG at the end of each respective period.

12. Fair Value Measurements

Certain of EOG's financial and nonfinancial assets and liabilities are reported at fair value on the Consolidated Balance Sheets. As more fully discussed in Note 12 to the Consolidated Financial Statements included in EOG's 2009 Annual Report, EOG adopted the provisions of the Fair Value Measurements and Disclosures Topic of the ASC for its financial and nonfinancial assets and liabilities. 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, 2010 and December 31, 2009 (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, 2010				
Financial Assets:				
Crude Oil and Natural Gas Price Swaps	$ -	$ 50	$ -	$ 50
Natural Gas Swaptions	-	43	-	43
Financial Liabilities:				
Natural Gas Basis Swaps	$ -	$ 29	$ -	$ 29
Foreign Currency Rate Swap	-	48	-	48
Contingent Consideration	-	-	17	17
At December 31, 2009				
Financial Assets:				
Natural Gas Collars, Price Swaps and Basis Swaps	$ -	$ 21	$ -	$ 21
Financial Liabilities:				
Natural Gas Collars, Price Swaps and Basis Swaps	$ -	$ 37	$ -	$ 37
Foreign Currency Rate Swap	-	49	-	49
Contingent Consideration	-	-	35	35

The estimated fair value of crude oil financial price swap contracts, natural gas financial collar, price swap and basis swap contracts and natural gas swaption contracts (see Note 13) was based upon forward commodity price curves based on quoted market prices. The estimated fair value of the foreign currency rate swap was based upon forward currency rates.

In connection with the acquisition of certain unproved acreage in Nacogdoches County, Texas, during the fourth quarter of 2009 and the first quarter of 2010, EOG could be required to make an additional one-time supplemental cash payment to the sellers contingent upon future natural gas prices over a five-year period (see Note 14). The fair value of the contingent consideration was estimated using present value techniques based upon an assessment of the probability that EOG would be required to make such future payment. Level 3 inputs used in such assessment include EOG's internal estimates of future natural gas prices and an appropriate risk-adjusted discount rate.

The following table presents the reconciliation of the beginning and ending fair value of EOG's contingent consideration liability measured using significant unobservable inputs (Level 3) during the nine-month period ended September 30, 2010 (in millions):

	Nine Months Ended September 30, 2010
Fair Value at Beginning of Period	$ 35
Additions (see Note 14)	3
Change in Fair Value Included in Earnings (1)	(21)
Fair Value at End of Period	$ 17

(1) Reflected as a reduction of depreciation, depletion and amortization.

The initial measurement of asset retirement obligations at fair value is calculated using discounted cash flow techniques and based on internal estimates of future retirement costs associated with property, plant and equipment. Significant Level 3 inputs used in the calculation of asset retirement obligations include plugging costs and reserve lives. A reconciliation of EOG's asset retirement obligations is presented in Note 7.

Proved oil and gas properties and other property, plant and equipment with a carrying amount of $757 million were written down to their fair value of $425 million, resulting in pretax impairment charges of $291 million in Canada (see Note 14) and $41 million in the United States for the nine months ended September 30, 2010. Significant Level 3 assumptions associated with the calculation of discounted cash flows used in the impairment analysis include EOG's estimate of future natural gas and crude oil prices, production costs, development expenditures, anticipated production of proved reserves, appropriate risk-adjusted discount rates and other relevant data. In connection with the impairment of shallow natural gas assets held for sale in Canada, EOG utilized accepted bids and estimates of customary closing adjustments and selling costs as the basis for determining fair value.

13. Risk Management Activities

Commodity Price Risk. As more fully discussed in Note 11 to the Consolidated Financial Statements included in EOG's 2009 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 natural gas and crude oil. EOG utilizes financial commodity derivative instruments, primarily collar, price swap 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. The financial impact of physical commodity contracts is included in revenues at the time of settlement, which in turn affects average realized hydrocarbon prices. EOG recognized net gains on the mark-to-market of financial commodity derivative contracts of $61 million and $21 million for the three months ended September 30, 2010 and 2009, respectively, and $106 million and $406 million for the nine months ended September 30, 2010 and 2009, respectively.

Financial Price Swap Contracts. Presented below is a comprehensive summary of EOG's natural gas and crude oil financial price swap contracts at September 30, 2010, with notional volumes expressed in million British thermal units per day (MMBtud) and in barrels per day (Bbld) and prices expressed in dollars per million British thermal units ($/MMBtu) and in dollars per barrel ($/Bbl), as applicable.

	Financial Price Swap Contracts			
	Natural Gas		Crude Oil	
	Volume (MMBtud)	Weighted Average Price ($/MMBtu)	Volume (Bbld)	Weighted Average Price ($/Bbl)
2010				
October 1, 2010 through December 31, 2010	-	$ -	2,000	$91.50
2011 [(1)]				
January 1, 2011 through December 31, 2011	150,000	$5.44	6,000	$93.18
2012 [(2)]				
January 1, 2012 through December 31, 2012	200,000	$5.57	-	$ -

(1) Includes unexercised swaption contracts which give a counterparty the option of entering into a price swap contract at a future date. Such option is exercisable on December 22, 2010. If the counterparty exercises this option, the notional volume of EOG's existing natural gas financial price swap contracts will increase by 100,000 MMBtud at an average price of $5.48 per million British thermal units (MMBtu) for the full year 2011.

(2) Includes unexercised swaption contracts which give counterparties the option of entering into price swap 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 financial price swap contracts will increase by 100,000 MMBtud at an average price of $5.71 per MMBtu for each month of 2012.

Subsequent to September 30, 2010, EOG entered into additional crude oil financial price swap contracts for the year 2011. For information on such contracts, see Management's Discussion and Analysis of Financial Condition and Results of Operations – Capital Resources and Liquidity – Commodity Derivative Transactions.

Financial Basis Swap Contracts. Prices received by EOG for its natural gas production generally vary from New York Mercantile Exchange (NYMEX) prices due to adjustments for delivery location (basis) and other factors. EOG utilizes natural gas financial basis swap contracts in order to fix the differential between prices in the Rocky Mountain area and NYMEX Henry Hub prices. Presented below is a comprehensive summary of EOG's natural gas financial basis swap contracts at September 30, 2010. The weighted average price differential represents the amount of reduction to NYMEX gas prices per MMBtu for the notional volumes covered by the basis swap contracts. The notional volumes are expressed in MMBtud and price differentials are expressed in $/MMBtu.

Natural Gas Financial Basis Swap Contracts		
	Volume (MMBtud)	Weighted Average Price Differential ($/MMBtu)
2010		
Fourth Quarter (1)	65,000	$(3.73)
2011		
First Quarter	65,000	$(1.89)

(1) Includes closed contracts for the month of October 2010.

Foreign Currency Exchange Rate Risk. As more fully described in Note 2 to the Consolidated Financial Statements included in EOG's 2009 Annual Report, EOG is party to a foreign currency swap transaction with multiple banks to eliminate any exchange rate impacts that may result from the $150 million aggregate principal amount of notes issued by one of EOG's Canadian subsidiaries in 2004. EOG accounts for the foreign currency swap transaction using the hedge accounting method. Changes in the fair value of the foreign currency swap do not impact Net Income. The after-tax net impact from the foreign currency swap transaction was a reduction in Other Comprehensive Income of $0.5 million and an increase in Other Comprehensive Income of $0.1 million for the three months ended September 30, 2010 and 2009, respectively, and an increase in Other Comprehensive Income of $3.5 million and $3.8 million for the nine months ended September 30, 2010 and 2009, respectively (see Note 5).

The following table sets forth the amount, on a gross basis, and classification of EOG's outstanding derivative financial instruments at September 30, 2010 and December 31, 2009. 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 master netting arrangements between EOG and the counterparties to the transactions (in millions):

Description	Location on Balance Sheet	Fair Value at September 30, 2010	Fair Value at December 31, 2009
Asset Derivatives [1]			
Crude Oil Price Swaps and Natural Gas Collars and Price Swaps -			
Current Portion	Assets from Price Risk Management Activities	$ 61	$ 50
Noncurrent Portion	Other Assets	$ 32	$ -
Liability Derivatives			
Natural Gas Basis Swaps -			
Current Portion	Liabilities from Price Risk Management Activities	$ 29	$ 57
Noncurrent Portion	Other Liabilities	$ -	$ 9
Foreign Currency Rate Swap - Noncurrent Portion	Other Liabilities	$ 48	$ 49

(1) Includes swaption contracts.

Credit Risk. Notional contract amounts are used to express the magnitude of commodity price and foreign currency swap agreements. The amounts potentially subject to credit risk, in the event of nonperformance by the other parties, are equal to the fair value of such contracts (see Note 12). 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, Inc. 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 ratings 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 12 for the aggregate fair value of all derivative instruments with credit-risk related contingent features that are in a net liability position at September 30, 2010 and December 31, 2009. EOG had no collateral posted at September 30, 2010 or December 31, 2009.

14. Asset Acquisitions and Dispositions

As previously reported, EOG began marketing its Canadian shallow natural gas assets in July 2010. In September 2010, EOG received acceptable bids for a portion of its shallow natural gas assets. Subsequent to September 30, 2010, EOG reached agreements with three separate parties to sell these assets for approximately $320 million, including an estimate of customary adjustments under each respective sales agreement. The transactions are expected to close during the fourth quarter of 2010. In the third quarter of 2010, EOG recorded a pretax impairment of $280 million to adjust the shallow natural gas assets to be sold to estimated fair value, less estimated cost to sell. At September 30, 2010, the Canadian shallow natural gas assets held for sale, and related liabilities, were included in Total Property, Plant and Equipment, Net ($322 million); Other Current Liabilities ($0.2 million); and Other Liabilities ($25 million) on the Consolidated Balance Sheets.

During the second quarter of 2010, EOG's wholly-owned Canadian subsidiary, EOG Resources Canada Inc. (EOG Canada), agreed to acquire the shares of Galveston LNG Inc., a Calgary-based corporation which, through its wholly-owned subsidiary, Kitimat LNG Inc. and affiliates, owns 49 percent of the planned liquefied natural gas (LNG) export terminal to be located at Bish Cove, near the Port of Kitimat, north of Vancouver, British Columbia. Preliminary construction costs, currently estimated to be approximately $3 billion (Canadian), will be revised at the conclusion of front-end engineering and design. In addition, Galveston LNG Inc. also owns a 24.5 percent interest in the proposed Pacific Trail Pipelines, an estimated $1 billion (Canadian) project, originating at Summit Lake, British Columbia. The pipeline is intended to link Western Canada's natural gas producing regions to the Kitimat LNG terminal. An affiliate of Apache Corporation owns 51 percent of the planned Kitimat LNG terminal and 25.5 percent interest in the proposed Pacific Trail Pipelines and will be the operator of the Kitimat LNG terminal. Under the terms of the agreement, EOG Canada's offer to purchase the shares of Galveston LNG Inc. is conditioned upon the achievement of certain commercial and regulatory milestones.

As more fully described in Note 17 to the Consolidated Financial Statements included in EOG's 2009 Annual Report, in the fourth quarter of 2009, EOG entered into an agreement to acquire unproved acreage in Nacogdoches County, Texas, within the Haynesville and Bossier Shale formations (Haynesville Assets). The acquisition agreement provides for an additional one-time supplemental cash payment to the sellers of the Haynesville Assets that is contingent on the satisfaction of certain conditions (within a five-year period beginning on the principal closing date) set forth in the acquisition agreement with respect to future natural gas prices. EOG estimated the fair value of the contingent consideration as of the acquisition dates in accordance with the provisions of the Business Combinations Topic of the ASC and has included such amount in Other Liabilities on the Consolidated Balance Sheets. In accordance with the acquisition agreement, EOG acquired additional Haynesville Assets at a final closing which occurred in the first quarter of 2010. The total consideration recorded in 2010 for the acquisition of the Haynesville Assets was $18 million, including the contingent consideration. The estimated fair value of the contingent consideration, including $3 million of contingent consideration related to the 2010 acquisition, was $17 million at September 30, 2010 (see Note 12).

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) 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 capital by controlling operating and capital costs. 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 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 has 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 future natural gas and crude oil production. Production in the United States and Canada accounted for approximately 83% of total company production in the first nine months of 2010 as compared to 86% in the first nine months of 2009. EOG has placed an emphasis on applying its horizontal drilling expertise gained in natural gas resource plays to unconventional oil reservoirs. In 2010, EOG is focusing its efforts on developing its existing North American crude oil and condensate and natural gas liquids acreage and capturing additional North American horizontal oil plays. During the first nine months of 2010, the North Dakota Bakken and Fort Worth Basin Barnett Shale areas produced an increasing amount of crude oil and condensate and natural gas liquids as compared to the comparable period in 2009. EOG holds approximately 505,000 net acres in the mature oil window of the Eagle Ford Shale Play in South Texas where it has drilled and completed approximately 40 wells. EOG expects significant crude oil production from this area beginning in 2011. For the first nine months of 2010, crude oil and condensate and natural gas liquids production accounted for approximately 26% of total company production as compared to 22% for the comparable period in 2009. Based on current trends, EOG expects its 2010 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 2009. EOG's major producing areas are in Louisiana, New Mexico, North Dakota, Texas, Utah, Wyoming and western Canada.

During the second quarter of 2010, EOG's wholly-owned Canadian subsidiary, EOG Resources Canada Inc. (EOG Canada), agreed to acquire the shares of Galveston LNG Inc., a Calgary-based corporation which, through its wholly-owned subsidiary, Kitimat LNG Inc. and affiliates, owns 49 percent of the planned liquefied natural gas (LNG) export terminal to be located at Bish Cove, near the Port of Kitimat, about 405 miles north of Vancouver, British Columbia. Planned capacity of the proposed Kitimat LNG terminal is about 700 million cubic feet of natural gas per day or five million metric tons of LNG per year. Preliminary construction costs, currently estimated to be approximately $3 billion (Canadian), will be revised at the conclusion of front-end engineering and design. In addition, Galveston LNG Inc. also owns a 24.5 percent interest in the proposed Pacific Trail Pipelines, an estimated $1 billion (Canadian), 300-mile project, originating at Summit Lake, British Columbia. The pipeline is intended to link western Canada's natural gas producing regions to the Kitimat LNG terminal. An affiliate of Apache Corporation owns 51 percent of the planned Kitimat LNG terminal and a 25.5 percent interest in the proposed Pacific Trail Pipelines and will be the operator of the Kitimat LNG terminal. Under the terms of the agreement, EOG Canada's offer to purchase the shares of Galveston LNG Inc. is conditioned upon the achievement of certain commercial and regulatory milestones.

As previously reported, EOG began marketing its Canadian shallow natural gas assets in July 2010. In September 2010, EOG received acceptable bids for a portion of its shallow natural gas assets. Subsequent to September 30, 2010, EOG reached agreements with three separate parties to sell these assets for approximately $320 million, including an estimate of customary adjustments under each respective sales agreement. The transactions are expected to close during the fourth quarter of 2010. In the third quarter of 2010, EOG recorded a pretax impairment of $280 million to adjust the shallow natural gas assets to be sold to estimated fair value, less estimated cost to sell. The Canadian shallow natural gas assets being sold represent approximately 4% of EOG's total 2009 production and approximately 3% of EOG's total year-end proved reserves.

International. In the United Kingdom, EOG plans to submit a field development plan to the United Kingdom Department of Energy and Climate Change in the fourth quarter of 2010 for its 2009 East Irish Sea oil discovery designated as the Conwy field. EOG has a 100% working interest in this field.

During the third quarter of 2010, EOG drilled two additional horizontal wells in the Sichuan Basin, Sichuan Province, The People's Republic of China. During the fourth quarter of 2010, EOG plans to complete one of the two horizontal wells drilled during the third quarter. EOG expects to complete its evaluation of the economic viability of this project in early 2011.

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

Capital Structure. One of management's key strategies is to maintain a strong balance sheet with a consistently below average debt-to-total capitalization ratio as compared to those in EOG's peer group. EOG's debt-to-total capitalization ratio was 27% at September 30, 2010 compared to 22% at December 31, 2009. As used in this calculation, total capitalization represents the sum of total current and long-term debt and total stockholders' equity. On May 20, 2010, EOG completed its public offering of $500 million aggregate principal amount of 2.95% Senior Notes due 2015 and $500 million aggregate principal amount of 4.40% Senior Notes due 2020 (together, Notes). Interest on the Notes is payable semi-annually in arrears on June 1 and December 1 of each year, beginning December 1, 2010. Net proceeds from the offering of approximately $990 million were used for general corporate purposes, including the repayment of outstanding commercial paper borrowings. In September 2010, EOG entered into an additional $1.0 billion unsecured Revolving Credit Agreement with domestic and foreign lenders (2010 Agreement). The 2010 Agreement matures on September 10, 2013. At September 30, 2010, there were no borrowings or letters of credit outstanding under the 2010 Agreement. See Note 11 to the Consolidated Financial Statements. During the first nine months of 2010, EOG funded $4.1 billion in exploration and development and other property, plant and equipment expenditures, paid $114 million in dividends to common stockholders and repaid $37 million of long-term debt, primarily by utilizing cash provided from its operating activities, cash on hand, proceeds from the offering of the Notes, proceeds from sales of assets and commercial paper borrowings.

For 2010, EOG's budget for exploration and development and other property, plant and equipment expenditures is approximately $5.7 billion, excluding acquisitions. United States and Canada crude oil drilling activity and, to a lesser extent, natural gas drilling activity will be the key components of these expenditures. EOG expects capital expenditures to be greater than cash generated from operations for both 2010 and 2011. EOG's business plan involves selling certain assets in 2010 and additional assets in 2011 to partially cover these anticipated shortfalls. EOG has set its maximum debt-to-total capitalization ratio at 30 percent to 35 percent.

Results of Operations

The following review of operations for the three and nine months ended September 30, 2010 and 2009 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, 2010 vs. Three Months Ended September 30, 2009

Net Operating Revenues. During the third quarter of 2010, net operating revenues increased $575 million, or 57%, to $1,582 million from $1,007 million for the same period of 2009. Total wellhead revenues, which are revenues generated from sales of EOG's production of natural gas, crude oil and condensate and natural gas liquids, for the third quarter of 2010 increased $367 million, or 43%, to $1,216 million from $849 million for the same period of 2009. During the third quarter of 2010, EOG recognized net gains on the mark-to-market of financial commodity derivative contracts of $61 million compared to net gains of $21 million for the same period of 2009. Gathering, processing and marketing revenues, which are revenues generated from sales of third-party natural gas, crude oil and condensate and natural gas liquids as well as gathering fees associated with gathering third-party natural gas, for the third quarter of 2010 increased $99 million, or 74%, to $234 million from $135 million for the same period of 2009. Gains (losses) on property dispositions of $65 million for the third quarter of 2010 primarily consist of gains on property dispositions in the Rocky Mountain area.

Wellhead volume and price statistics for the three-month periods ended September 30, 2010 and 2009 were as follows:

	Three Months Ended September 30, 2010	Three Months Ended September 30, 2009
Natural Gas Volumes (MMcfd) (1)		
United States	1,175	1,128
Canada	200	219
Trinidad	333	268
Other International (2)	14	13
Total	1,722	1,628
Average Natural Gas Prices ($/Mcf) (3)		
United States	$ 4.21	$ 3.27
Canada	3.42	3.15
Trinidad	2.53	1.77
Other International (2)	5.41	3.53
Composite	3.80	3.01
Crude Oil and Condensate Volumes (MBbld) (1)		
United States	66.6	51.7
Canada	5.9	4.7
Trinidad	4.8	3.0
Other International (2)	0.1	0.1
Total	77.4	59.5
Average Crude Oil and Condensate Prices ($/Bbl) (3)		
United States	$ 71.54	$ 60.79
Canada	69.12	61.43
Trinidad	65.06	57.07
Other International (2)	74.14	57.93
Composite	70.96	60.65
Natural Gas Liquids Volumes (MBbld) (1)		
United States	31.1	23.1
Canada	0.8	1.0
Total	31.9	24.1
Average Natural Gas Liquids Prices ($/Bbl) (3)		
United States	$ 36.56	$ 31.15
Canada	40.34	30.96
Composite	36.66	31.14
Natural Gas Equivalent Volumes (MMcfed) (4)		
United States	1,761	1,577
Canada	240	253
Trinidad	362	286
Other International (2)	15	13
Total	2,378	2,129
Total Bcfe (4)	218.8	195.9

(1) Million cubic feet per day or thousand barrels per day, as applicable.
(2) Other International includes EOG's United Kingdom and China operations.
(3) Dollars per thousand cubic feet or per barrel, as applicable. Excludes the impact of financial commodity derivative instruments (see Note 13 to the Consolidated Financial Statements).
(4) Million cubic feet equivalent per day or billion cubic feet equivalent, as applicable; includes natural gas, crude oil and condensate and natural gas liquids. Natural gas equivalents are determined using the ratio of 6.0 thousand cubic feet of natural gas to 1.0 barrel of crude oil and condensate or natural gas liquids. Bcfe is calculated by multiplying the MMcfed amount by the number of days in the period and then dividing that amount by one thousand.

Wellhead natural gas revenues for the third quarter of 2010 increased $152 million, or 34%, to $602 million from $450 million for the same period of 2009. The increase was due to a higher composite average wellhead natural gas price ($126 million) and increased natural gas deliveries ($26 million). EOG's composite average wellhead natural gas price increased 26% to $3.80 per thousand cubic feet (Mcf) for the third quarter of 2010 from $3.01 per Mcf for the same period of 2009.

Natural gas deliveries for the third quarter of 2010 increased 94 MMcfd, or 6%, to 1,722 MMcfd from 1,628 MMcfd for the same period of 2009. The increase was primarily due to higher production in Trinidad (65 MMcfd) and in the United States (47 MMcfd), partially offset by decreased production in Canada (19 MMcfd). The increase in Trinidad was primarily attributable to deliveries under a take-or-pay contract, which began January 1, 2010. The increase in the United States was primarily attributable to increased production in Louisiana (65 MMcfd), Texas (37 MMcfd) and Pennsylvania (12 MMcfd), partially offset by decreased production in the Rocky Mountain area (32 MMcfd), offshore Gulf of Mexico (16 MMcfd), Mississippi (8 MMcfd) and New Mexico (7 MMcfd).

Wellhead crude oil and condensate revenues for the third quarter of 2010 increased $177 million, or 54%, to $507 million from $330 million for the same period of 2009, due to an increase of 18 MBbld, or 30%, in wellhead crude oil and condensate deliveries ($103 million) and a higher composite average wellhead crude oil and condensate price ($74 million). The increase in deliveries primarily reflects increased production in Texas (8 MBbld), North Dakota (5 MBbld), Trinidad (2 MBbld) and Colorado (2 MBbld). EOG's composite average wellhead crude oil and condensate price for the third quarter of 2010 increased 17% to $70.96 per barrel compared to $60.65 per barrel for the same period of 2009.

Natural gas liquids revenues for the third quarter of 2010 increased $38 million, or 56%, to $107 million from $69 million for the same period of 2009, due to an increase of 8 MBbld, or 32%, in natural gas liquids deliveries ($22 million) and a higher composite average price ($16 million). The increase in deliveries primarily reflects increased volumes in the Fort Worth Basin Barnett Shale area. EOG's composite average natural gas liquids price for the third quarter of 2010 increased 18% to $36.66 per barrel compared to $31.14 per barrel for the same period of 2009.

During the third quarter of 2010, EOG recognized net gains on the mark-to-market of financial commodity derivative contracts of $61 million compared to net gains of $21 million for the same period of 2009. During the third quarter of 2010, the cash outflow related to settled natural gas financial basis swap contracts was $14 million compared to the net cash inflow related to settled natural gas financial collar, price swap and basis swap contracts of $331 million for the same period of 2009.

Gathering, processing and marketing revenues represent sales of third-party natural gas, crude oil and condensate and natural gas liquids as well as gathering fees associated with gathering third-party natural gas. During the three months and nine months ended September 30, 2010 and 2009, gathering, processing and marketing revenues were primarily related to sales of third-party crude oil and natural gas. The purchase and sale 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 2010, gathering, processing and marketing revenues and marketing costs increased primarily as a result of increased crude oil marketing activities. Gathering, processing and marketing revenues less marketing costs for the third quarter of 2010 totaled $2 million compared to $3 million for the same period of 2009.

Operating and Other Expenses. For the third quarter of 2010, operating expenses of $1,594 million were $622 million higher than the $972 million incurred in the third quarter of 2009. The following table presents the costs per thousand cubic feet equivalent (Mcfe) for the three-month periods ended September 30, 2010 and 2009:

	Three Months Ended September 30, 2010	Three Months Ended September 30, 2009
Lease and Well	$ 0.83	$ 0.73
Transportation Costs	0.47	0.36
Depreciation, Depletion and Amortization (DD&A) -		
Oil and Gas Properties (1)	2.18	1.84
Other Property, Plant and Equipment	0.12	0.13
General and Administrative (G&A)	0.37	0.32
Interest Expense, Net	0.15	0.16
Total (2)	$ 4.12	$ 3.54

(1) The 2010 amount excludes the reduction in the estimated fair value of the contingent consideration liability of $2 million, or $0.01 per Mcfe (see Note 12 to the Consolidated Financial Statements).

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

The primary factors impacting the cost components of per-unit rates of lease and well, transportation costs, DD&A, G&A and interest expense, net for the three months ended September 30, 2010 compared to the same period of 2009 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 EOG's natural gas and crude oil wells, the cost of workovers and lease and well administrative expenses. Operating and maintenance expenses 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 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 costs for wells producing crude oil and condensate are higher than operating costs for wells producing natural gas.

Lease and well expenses of $181 million for the third quarter of 2010 increased $39 million from $142 million for the same prior year period primarily due to higher operating and maintenance expenses in the United States ($19 million) and Canada ($7 million), increased lease and well administrative expenses in the United States ($8 million), increased workover expenditures in the United States ($3 million) and unfavorable changes in the Canadian exchange rate ($2 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 EOG's crude-by-rail operations.

Transportation costs of $103 million for the third quarter of 2010 increased $32 million from $71 million for the same prior year period primarily due to increased transportation costs in the Rocky Mountain area ($13 million), the Upper Gulf Coast area ($12 million) and the Fort Worth Basin Barnett Shale area ($7 million). These increases reflect costs associated with marketing arrangements to transport production to downstream markets. The increased transportation costs in the Rocky Mountain area also include costs associated with EOG’s crude-by-rail operations.

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 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. Other property, plant and equipment consist of gathering and processing assets, compressors, crude-by-rail assets, vehicles, buildings and leasehold improvements, furniture and fixtures, and computer hardware and software.

DD&A expenses for the third quarter of 2010 increased $116 million to $501 million from $385 million for the same prior year period. DD&A expenses associated with oil and gas properties for the third quarter of 2010 were $114 million higher than the same prior year period primarily due to higher unit rates in the United States ($49 million), Canada ($20 million), Trinidad ($5 million) and China ($3 million); unfavorable changes in the Canadian exchange rate ($4 million); and increased production in the United States ($35 million) and Trinidad ($3 million); partially offset by decreased production in Canada ($3 million).

DD&A expenses associated with other property, plant and equipment for the third quarter of 2010 were $2 million higher than the same prior year period primarily due to natural gas gathering systems and processing plants placed in service in the Rocky Mountain area in early 2010.

G&A expenses of $81 million for the third quarter of 2010 increased $19 million compared to the same prior year period primarily due to higher employee-related costs ($8 million), legal and other professional fees ($3 million) and information system costs ($2 million).

Interest expense, net of $33 million for the third quarter of 2010 increased $2 million compared to the same prior year period primarily due to a higher average debt balance ($9 million), partially offset by higher capitalized interest ($6 million).

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 for the third quarter of 2010 increased $5 million to $18 million compared to the same prior year period primarily due to increased activities in the Rocky Mountain ($3 million) and Fort Worth Basin Barnett Shale ($3 million) areas.

Impairments include amortization of unproved oil and gas property costs, as well as impairments of proved oil and gas properties. 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 discounting the future cash flows at an appropriate risk-adjusted discount rate. For certain of the Canadian shallow natural gas assets held for sale (as discussed above), EOG utilized accepted bids as the basis for determining fair value.

Impairments of $353 million for the third quarter of 2010 increased $284 million from $69 million for the same prior year period primarily due to increased impairments of proved properties and other property, plant and equipment in Canada ($265 million) and the United States ($5 million), unfavorable changes in the Canadian exchange rate ($17 million) and increased amortization of unproved property costs in Canada ($7 million), partially offset by decreased amortization of unproved property costs in the United States ($10 million). EOG recorded impairments of proved properties and other property, plant and equipment of $302 million and $15 million for the third quarter of 2010 and 2009, respectively. Included in the third quarter 2010 amount were impairments of $280 million associated with Canadian shallow natural gas assets held for sale (see Note 14 to the Consolidated Financial Statements).

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 2010 increased $26 million to $74 million (6.1% of wellhead revenues) from $48 million (5.6% of wellhead revenues) for the same prior year period. The increase in taxes other than income was primarily due to an increase in severance/production taxes as a result of increased wellhead revenues in the United States ($14 million) and Trinidad ($5 million) and a decrease in credits available to EOG in 2010 for Texas high cost gas severance tax rate reductions as a result of fewer wells qualifying for such credit ($5 million).

Other income (expense), net of $6 million for the third quarter of 2010 increased $6 million from the same prior year period. The increase was primarily due to higher net foreign currency transaction gains ($3 million) and higher equity income from EOG's investment in ammonia plants in Trinidad ($2 million).

Income tax provision of $32 million for the third quarter of 2010 increased $32 million compared to the same prior year period due primarily to taxes associated with increased pretax earnings in the United States and Trinidad, partially offset by the tax effect of the Canadian shallow natural gas asset impairment. The statutory tax rates in the United States and Trinidad are higher than the Canadian statutory rate.

Nine Months Ended September 30, 2010 vs. Nine Months Ended September 30, 2009

Net Operating Revenues. During the first nine months of 2010, net operating revenues increased $1,285 million, or 42%, to $4,311 million from $3,026 million for the same period of 2009. Total wellhead revenues for the first nine months of 2010 increased $1,152 million, or 49%, to $3,516 million from $2,364 million for the same period of 2009. During the first nine months of 2010, EOG recognized net gains on the mark-to-market of financial commodity derivative contracts of $106 million compared to net gains of $406 million for the same period of 2009. Gathering, processing and marketing revenues for the first nine months of 2010 increased $352 million, or 141%, to $602 million from $250 million for the same period of 2009. Gains (losses) on property dispositions of $72 million for the first nine months of 2010 primarily consist of gains on property dispositions in the Rocky Mountain area.

Wellhead volume and price statistics for the nine-month periods ended September 30, 2010 and 2009 were as follows:

	Nine Months Ended September 30, 2010	Nine Months Ended September 30, 2009
Natural Gas Volumes (MMcfd)		
United States	1,096	1,153
Canada	205	224
Trinidad	342	266
Other International	15	15
Total	1,658	1,658
Average Natural Gas Prices ($/Mcf) (1)		
United States	$ 4.50	$ 3.57
Canada	4.09	3.67
Trinidad	2.54	1.54
Other International	4.64	4.45
Composite	4.05	3.27
Crude Oil and Condensate Volumes (MBbld)		
United States	59.5	46.5
Canada	6.1	3.6
Trinidad	4.7	3.0
Other International	0.1	0.1
Total	70.4	53.2
Average Crude Oil and Condensate Prices ($/Bbl) (1)		
United States	$ 72.58	$ 49.54
Canada	71.32	51.91
Trinidad	66.91	46.13
Other International	72.80	50.11
Composite	72.09	49.51
Natural Gas Liquids Volumes (MBbld)		
United States	27.4	22.2
Canada	0.9	1.1
Total	28.3	23.3
Average Natural Gas Liquids Prices ($/Bbl) (1)		
United States	$ 40.68	$ 26.42
Canada	42.90	27.29
Composite	40.75	26.46
Natural Gas Equivalent Volumes (MMcfed)		
United States	1,617	1,566
Canada	247	252
Trinidad	370	284
Other International	16	15
Total	2,250	2,117
Total Bcfe	614.1	578.1

(1) Excludes the impact of financial commodity derivative instruments (see Note 13 to the Consolidated Financial Statements).

Wellhead natural gas revenues for the first nine months of 2010 increased $355 million, or 24%, to $1,833 million from $1,478 million for the same period of 2009. The increase was due to a higher composite average wellhead natural gas price. EOG's composite average wellhead natural gas price increased 24% to $4.05 per Mcf for the first nine months of 2010 from $3.27 per Mcf for the same period of 2009.

Natural gas deliveries for both the first nine months of 2010 and 2009 were 1,658 MMcfd. Increased natural gas production in Trinidad (76 MMcfd) was offset by decreased production in the United States (57 MMcfd) and Canada (19 MMcfd). The increase in Trinidad was primarily attributable to deliveries under a take-or-pay contract, which began January 1, 2010. The decrease in the United States was primarily attributable to decreased production in Texas (54 MMcfd), the Rocky Mountain area (27 MMcfd), offshore Gulf of Mexico (10 MMcfd), New Mexico (8 MMcfd) and Kansas (6 MMcfd), partially offset by increased production in Louisiana (40 MMcfd) and Pennsylvania (10 MMcfd).

Wellhead crude oil and condensate revenues for the first nine months of 2010 increased $650 million, or 91%, to $1,368 million from $718 million for the same period of 2009, due to a higher composite average wellhead crude oil and condensate price ($428 million) and an increase of 17 MBbld, or 32%, in wellhead crude oil and condensate deliveries ($222 million). The increase in deliveries primarily reflects increased production in North Dakota (12 MBbld) and Texas (5 MBbld). EOG's composite average wellhead crude oil and condensate price for the first nine months of 2010 increased 46% to $72.09 per barrel compared to $49.51 per barrel for the same period of 2009.

Natural gas liquids revenues for the first nine months of 2010 increased $147 million, or 87%, to $315 million from $168 million for the same period of 2009, due to a higher composite average price ($110 million) and an increase of 5 MBbld, or 21%, in natural gas liquids deliveries ($37 million). The increase in deliveries primarily reflects increased volumes in the Fort Worth Basin Barnett Shale area. EOG's composite average natural gas liquids price for the first nine months of 2010 increased 54% to $40.75 per barrel compared to $26.46 per barrel for the same period of 2009.

During the first nine months of 2010, EOG recognized net gains on mark-to-market financial commodity derivative contracts of $106 million compared to net gains of $406 million for the same period of 2009. During the first nine months of 2010, the net cash inflow related to settled natural gas financial collar, price swap and basis swap contracts was $25 million compared to a net cash inflow related to settled natural gas financial price swap and basis swap contracts of $987 million for the same period of 2009.

During the first nine months of 2010, gathering, processing and marketing revenues and marketing costs increased primarily as a result of increased crude oil marketing activities. Gathering, processing and marketing revenues less marketing costs for the first nine months of 2010 totaled $10 million compared to $12 million for the same period of 2009. The decline resulted primarily from lower natural gas marketing margins.

Operating and Other Expenses. For the first nine months of 2010, operating expenses of $3,962 million were $1,253 million higher than the $2,709 million incurred in the same period of 2009. The following table presents the costs per Mcfe for the nine-month periods ended September 30, 2010 and 2009:

	Nine Months Ended September 30,	
	2010	**2009**
Lease and Well	$ 0.83	$ 0.73
Transportation Costs	0.47	0.36
DD&A -		
Oil and Gas Properties (1)	2.18	1.87
Other Property, Plant and Equipment	0.13	0.12
G&A	0.34	0.31
Interest Expense, Net	0.14	0.13
Total (2)	$ 4.09	$ 3.52

(1) The 2010 amount excludes the reductions in the estimated fair value of the contingent consideration liability of $21 million, or $0.04 per Mcfe (see Note 12 to the Consolidated Financial Statements).

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

The primary factors impacting the cost components of per-unit rates of lease and well, transportation costs, DD&A, G&A and interest expense, net for the nine months ended September 30, 2010 compared to the same period of 2009 are set forth below.

Lease and well expenses of $508 million for the first nine months of 2010 increased $86 million from $422 million for the same prior year period primarily due to higher operating and maintenance expenses in the United States ($36 million) and Canada ($12 million), higher lease and well administrative expenses in the United States ($18 million), unfavorable changes in the Canadian exchange rate ($13 million) and increased workover expenditures in the United States ($5 million) and Canada ($2 million).

Transportation costs of $286 million for the first nine months of 2010 increased $80 million from $206 million for the same prior year period primarily due to increased transportation costs in the Rocky Mountain area ($42 million), the Fort Worth Basin Barnett Shale area ($22 million) and the Upper Gulf Coast area ($18 million). These increases reflect costs associated with marketing arrangements to transport production to downstream markets. The increased transportation costs in the Rocky Mountain area also include costs associated with EOG's crude-by-rail operations.

DD&A expenses for the first nine months of 2010 increased $248 million to $1,398 million from $1,150 million for the same prior year period. DD&A expenses associated with oil and gas properties for the first nine months of 2010 were $236 million higher than the same prior year period primarily due to higher unit rates in the United States ($101 million), Canada ($78 million), Trinidad ($12 million) and China ($6 million); unfavorable changes in the Canadian exchange rate ($27 million); and increased production in the United States ($27 million) and Trinidad ($9 million); partially offset by a change in the fair value of the contingent consideration liability ($21 million) and decreased production in Canada ($3 million).

DD&A expenses associated with other property, plant and equipment for the first nine months of 2010 were $12 million higher than the same prior year period primarily due to increased expenditures associated with natural gas gathering systems and processing plants placed in service in the Rocky Mountain area ($9 million) and the Fort Worth Basin Barnett Shale area ($4 million) in late 2009 and early 2010.

G&A expenses of $206 million for the first nine months of 2010 increased $27 million compared to the same prior year period primarily due to higher employee-related costs ($7 million), legal and other professional fees ($8 million), information system costs ($3 million) and insurance costs ($2 million).

Interest expense, net of $88 million for the first nine months of 2010 increased $15 million compared to the same prior year period primarily due to a higher average debt balance ($33 million), partially offset by higher capitalized interest ($19 million).

Gathering and processing costs for the first nine months of 2010 increased $3 million to $47 million compared to the same prior year period primarily due to increased activities in the Rocky Mountain area.

Exploration costs of $149 million for the first nine months of 2010 increased $20 million from $129 million for the same prior year period primarily due to increased geological and geophysical expenditures ($13 million) and increased employee-related exploration costs ($9 million) in the United States.

Impairments of $503 million for the first nine months of 2010 increased $321 million from $182 million for the same prior year period primarily due to increased impairments of proved properties and other property, plant and equipment in Canada ($258 million) and the United States ($2 million), unfavorable changes in the Canadian exchange rate ($36 million) and increased amortization of unproved property costs in the United States ($21 million) and Canada ($4 million). EOG recorded impairments of proved properties and other property, plant and equipment of $332 million and $39 million for the nine months ended September 30, 2010 and 2009, respectively. Included in the 2010 amount were impairments of $280 million associated with Canadian shallow natural gas assets held for sale (see Note 14 to the Consolidated Financial Statements).

Taxes other than income for the first nine months of 2010 increased $109 million to $228 million (6.5% of wellhead revenues) from $119 million (5.0% of wellhead revenues) for the same prior year period. The increase in taxes other than income was primarily due to increased severance/production taxes primarily as a result of increased wellhead revenues in the United States ($42 million), Trinidad ($17 million) and Canada ($4 million); a decrease in credits available to EOG in 2010 for Texas high cost gas severance tax rate reductions as a result of fewer wells qualifying for such credit ($32 million); and higher ad valorem/property taxes in the United States ($10 million).

Other income (expense), net was $8 million for the first nine months of 2010 compared to $3 million for the same prior year period. The increase of $5 million was primarily due to higher equity income from EOG's investment in ammonia plants in Trinidad ($7 million), partially offset by decreased foreign currency transaction gains ($2 million).

The income tax provision of $161 million for the first nine months of 2010 increased $62 million compared to the same prior year period due primarily to taxes associated with increased pretax earnings in the United States and Trinidad, partially offset by the tax effect of the Canadian shallow natural gas asset impairment. The statutory tax rates in the United States and Trinidad are higher than the Canadian statutory rate.

Capital Resources and Liquidity

Cash Flow. The primary sources of cash for EOG during the nine months ended September 30, 2010 were funds generated from operations, net proceeds from the issuance of the Notes, proceeds from the sale of oil and gas properties, net proceeds from commercial paper and uncommitted credit facility borrowings and proceeds from stock options exercised and employee stock purchase plan activity. The primary uses of cash were funds used in operations; exploration and development expenditures; other property, plant and equipment expenditures; dividend payments to stockholders; and repayment of long-term debt. During the first nine months of 2010, EOG's cash balance decreased $658 million to $28 million from $686 million at December 31, 2009.

Net cash provided by operating activities of $2,086 million for the first nine months of 2010 decreased $8 million compared to the same period of 2009 primarily reflecting an unfavorable change in net cash flow from the settlement of financial commodity derivative contracts ($962 million), an increase in cash operating expenses ($317 million), an increase in net cash paid for income taxes ($142 million), and an increase in cash paid for interest expense ($17 million), partially offset by an increase in wellhead revenues ($1,152 million) and favorable changes in working capital and other assets and liabilities ($152 million).

Net cash used in investing activities of $3,625 million for the first nine months of 2010 increased by $974 million compared to the same period of 2009 due primarily to an increase in additions to oil and gas properties ($1,473 million), partially offset by favorable changes in working capital associated with investing activities ($363 million), an increase in proceeds from sales of assets ($124 million) and a decrease in additions to other property, plant and equipment ($18 million).

Net cash provided by financing activities of $882 million for the first nine months of 2010 included the issuance of the Notes ($991 million), net commercial paper borrowings ($34 million) and proceeds from stock options exercised and employee stock purchase plan activity ($25 million). Cash used in financing activities for the first nine months of 2010 included cash dividend payments ($114 million), the repayment of long-term debt ($37 million), the purchase of treasury stock ($10 million) and debt issuance costs ($6 million). Net cash provided by financing activities of $823 million for the first nine months of 2009 included a long-term debt borrowing ($900 million), excess tax benefits from stock-based compensation ($34 million) and proceeds from stock options exercised and employee stock purchase plan activity ($14 million). Cash used in financing activities for the first nine months of 2009 included cash dividend payments ($106 million), the purchase of treasury stock ($10 million) and debt issuance costs ($9 million).

Total Expenditures. For 2010, EOG's budget for exploration and development and other property, plant and equipment expenditures is approximately $5.7 billion, excluding acquisitions. The table below sets out components of total expenditures for the nine-month periods ended September 30, 2010 and 2009 (in millions):

	Nine Months Ended September 30, 2010	Nine Months Ended September 30, 2009
Expenditure Category		
Capital		
Drilling and Facilities	$ 3,263	$ 1,780
Leasehold Acquisitions	354	293
Property Acquisitions (1)	24	206
Capitalized Interest	57	38
Subtotal	3,698	2,317
Exploration Costs	149	129
Dry Hole Costs	45	40
Exploration and Development Expenditures	3,892	2,486
Asset Retirement Costs	79	53
Total Exploration and Development Expenditures	3,971	2,539
Other Property, Plant and Equipment	223	241
Total Expenditures	$ 4,194	$ 2,780

(1) In 2010, property acquisitions included contingent consideration, with an estimated fair value of $3 million, related to the acquisition of the Haynesville Assets (see Note 14 to the Consolidated Financial Statements).

Exploration and development expenditures of $3,892 million for the first nine months of 2010 were $1,406 million higher than the same period of 2009 due primarily to increased drilling and facilities expenditures in the United States ($1,269 million), Canada ($91 million), Trinidad ($74 million) and China ($26 million); increased leasehold acquisition expenditures in the United States ($64 million); unfavorable changes in the foreign currency exchange rate in Canada ($34 million); increased capitalized interest in the United States ($19 million); and increased exploration costs in the United States ($24 million); partially offset by decreased property acquisition expenditures in the United States ($182 million). The exploration and development expenditures for the first nine months of 2010 of $3,892 million include $3,007 million in development, $804 million in exploration, $57 million in capitalized interest and $24 million in property acquisitions. The exploration and development expenditures for the first nine months of 2009 of $2,486 million include $1,589 million in development, $653 million in exploration, $206 million in property acquisitions and $38 million in capitalized interest.

The level of exploration and development expenditures, including acquisitions, will vary in future periods depending on energy market conditions and other related economic factors. EOG has significant flexibility with respect to financing alternatives and the ability to adjust its exploration and development and other property, plant and equipment expenditure budget as circumstances warrant. While EOG has certain continuing commitments associated with expenditure plans related to operations in the United States, Canada, Trinidad, the United Kingdom and China, 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, 2009, filed on February 25, 2010, 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 natural gas and crude oil. EOG utilizes financial commodity derivative instruments, primarily collar, price swap 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 on the Consolidated Statements of 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.

Financial Price Swap Contracts. The total fair value of EOG's natural gas and crude oil financial price swap contracts at September 30, 2010 was a positive $73 million and $20 million, respectively, which is reflected in the Consolidated Balance Sheets. Presented below is a comprehensive summary of EOG's natural gas and crude oil financial price swap contracts at November 2, 2010, with notional volumes expressed in million British thermal units per day (MMBtud) and in barrels per day (Bbld) and prices expressed in dollars per million British thermal units ($/MMBtu) and in dollars per barrel ($/Bbl), as applicable.

	Financial Price Swap Contracts			
	Natural Gas		Crude Oil	
	Volume (MMBtud)	Weighted Average Price ($/MMBtu)	Volume (Bbld)	Weighted Average Price ($/Bbl)
2010 [1]				
October 1, 2010 through December 31, 2010	-	$ -	2,000	$91.50
2011 [2]				
January 1, 2011 through December 31, 2011	150,000	$5.44	10,000	$90.39
2012 [3]				
January 1, 2012 through December 31, 2012	200,000	$5.57	-	$ -

(1) Includes closed contracts for the month of October 2010.

(2) Includes unexercised swaption contracts which give a counterparty the option of entering into a price swap contract at a future date. Such option is exercisable on December 22, 2010. If the counterparty exercises this option, the notional volume of EOG's existing natural gas financial price swap contracts will increase by 100,000 MMBtud at an average price of $5.48 per million British thermal units (MMBtu) for the full year 2011.

(3) Includes unexercised swaption contracts which give counterparties the option of entering into price swap 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 financial price swap contracts will increase by 100,000 MMBtud at an average price of $5.71 per MMBtu for each month of 2012.

Financial Basis Swap Contracts. Prices received by EOG for its natural gas production generally vary from New York Mercantile Exchange (NYMEX) prices due to adjustments for delivery location (basis) and other factors. EOG utilizes natural gas financial basis swap contracts in order to fix the differential between prices in the Rocky Mountain area and NYMEX Henry Hub prices. The total fair value of EOG's natural gas financial basis swap contracts at September 30, 2010 was a negative $29 million, which is reflected in the Consolidated Balance Sheets. Presented below is a comprehensive summary of EOG's natural gas financial basis swap contracts at November 2, 2010. The weighted average price differential represents the amount of reduction to NYMEX gas prices per MMBtu for the notional volumes covered by the basis swap. The notional volumes are expressed in MMBtud and price differentials expressed in $/MMBtu.

	Natural Gas Financial Basis Swap Contracts	
	Volume (MMBtud)	Weighted Average Price Differential ($/MMBtu)
2010		
Fourth Quarter [1]	65,000	$(3.73)
2011		
First Quarter	65,000	$(1.89)

(1) Includes closed contracts for the months of October and November 2010.

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 or generate income or cash flows 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 natural gas, crude oil and related commodities;
- changes in demand for natural gas, crude oil and related commodities, including ammonia and methanol;
- the extent to which EOG is successful in its efforts to discover and market reserves and to acquire natural gas and crude oil properties;
- the extent to which EOG can optimize reserve recovery and economically develop its plays utilizing horizontal and vertical drilling and advanced completion technologies;
- 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 natural gas and crude oil exploration and development projects, given the risks and uncertainties inherent in drilling, completing and operating natural gas and crude oil wells and the potential for interruptions of production, whether involuntary or intentional as a result of market or other conditions;
- 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;
- changes in government policies, laws and regulations, including environmental and tax laws and regulations;
- 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;
- EOG's ability to obtain access to surface locations for drilling and production facilities;
- the extent to which EOG's third-party-operated natural gas and crude oil properties are operated successfully and economically;
- EOG's ability to effectively integrate acquired natural gas and crude oil 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;
- weather, including its impact on natural gas and crude oil 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;
- the accuracy of reserve estimates, which by their nature involve the exercise of professional judgment and may therefore be imprecise;

- 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 extent and effect of any hedging activities engaged in by EOG;
- the timing and impact of liquefied natural gas imports;
- the use of competing energy sources and the development of alternative energy sources;
- the extent to which EOG incurs uninsured losses and liabilities;
- acts of war and terrorism and responses to these acts; and
- the other factors described under Item 1A, "Risk Factors," on pages 14 through 19 of EOG's Annual Report on Form 10-K for the year ended December 31, 2009.

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 37 through 41 of EOG's Annual Report on Form 10-K for the year ended December 31, 2009, filed on February 25, 2010 (EOG's 2009 Annual Report); and (ii) Note 11, "Risk Management Activities," on pages F-25 through F-28, to EOG's Consolidated Financial Statements included in EOG's 2009 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 13 to 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 by EOG in the reports it 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 9 to Consolidated Financial Statements, which is incorporated herein by reference.

As previously reported by EOG Resources, Inc. (EOG) in its Form 10-Q for the quarterly period ended June 30, 2010, a well control incident occurred on June 3, 2010 at the EOG-operated Punxsutawney Hunt Club #36H natural gas well in Clearfield County, Pennsylvania. The Pennsylvania Fish and Boat Commission (PFBC) has alleged that the incident resulted in contamination of area waters, in violation of the water pollution provisions of the Pennsylvania Fish and Boat Code. EOG is currently in discussions with the PFBC regarding the alleged violations and the monetary penalty sought by the PFBC, and anticipates resolving this matter in December 2010 or January 2011. This proceeding was instituted by the PFBC in August 2010.

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, 2010 - July 31, 2010	2,040	$ 102.66	-	6,386,200
August 1, 2010 - August 31, 2010	26,790	94.43	-	6,386,200
September 1, 2010 - September 30, 2010	2,771	90.95	-	6,386,200
Total	31,601	94.66	-	

(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. EOG did not repurchase any shares under the Board-authorized repurchase program during the third quarter of 2010.

ITEM 6. EXHIBITS

Exhibit No.		Description
10.1	-	Revolving Credit Agreement, dated as of September 10, 2010, among EOG, Bank of America, N.A., as Administrative Agent, the financial institutions as bank parties thereto, and the other parties thereto (incorporated by reference to Exhibit 10.1 to EOG's Current Report on Form 8-K, filed September 14, 2010).
* 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.
* **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 - Three Months Ended September 30, 2010 and 2009 and Nine Months Ended September 30, 2010 and 2009, (ii) the Consolidated Balance Sheets - September 30, 2010 and December 31, 2009, (iii) the Consolidated Statements of Cash Flows - Nine Months Ended September 30, 2010 and 2009 and (iv) Notes to Consolidated Financial Statements. Users of this data are advised pursuant to Rule 406T of Regulation S-T that this interactive data file is deemed not filed or part of a registration statement or prospectus for purposes of Sections 11 or 12 of the Securities Act of 1933, as amended, is deemed not filed for purposes of Section 18 of the Securities Exchange Act of 1934, as amended, and otherwise is not subject to liability under these sections.

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 2, 2010

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

EXHIBIT INDEX

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