EOG RESOURCES INC
Form 10-Q
August 06, 2009

UNITED STATES
SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

FORM
10-Q

(Mark One)

x

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

For the quarterly period ended June 30, 2009

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 x No o

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 (Section 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 x No o

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, or a smaller reporting company. See the definitions of "large accelerated filer," "accelerated filer" and "smaller reporting company" in Rule 12b-2 of the Exchange Act.

Large accelerated filer x Accelerated filer o Non-accelerated filer o Smaller reporting company o

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Exchange Act). Yes o No x

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	251,931,774 (as of August 3, 2009)

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 June 30,		Six Months Ended June 30,	
	2009	2008	2009	2008
Net Operating				

Revenues				
Natural Gas	$ 460,044	$ 1,340,557	$ 1,027,622	$ 2,378,195
Crude Oil, Condensate and Natural Gas Liquids	287,134	524,793	487,462	919,641
Gains (Losses) on Mark-to-Market Commodity Derivative Contracts	33,570	(842,822)	384,953	(1,312,666)
Gathering, Processing and Marketing	77,284	63,777	115,126	99,762
Other, Net	3,007	9,207	4,085	144,598
Total	861,039	1,095,512	2,019,248	2,229,530
Operating Expenses				
Lease and Well	134,599	129,949	280,105	254,056
Transportation Costs	66,011	63,102	134,873	125,069
Gathering and Processing Costs	13,521	8,922	31,234	17,281
Exploration Costs	34,307	59,511	83,930	107,454
Dry Hole Costs	33,643	6,785	36,637	15,213
Impairments	47,046	48,875	112,517	81,449
Marketing Costs	74,050	62,986	106,003	96,031
Depreciation, Depletion and Amortization	375,592	315,294	764,921	612,493
General and Administrative	58,760	61,640	116,706	114,566

Taxes Other Than Income	23,492	95,345	70,892	182,095
Total	861,021	852,409	1,737,818	1,605,707
Operating Income	18	243,103	281,430	623,823
Other Income, Net	1,237	13,309	2,976	14,892
Income Before Interest Expense and Income Taxes	1,255	256,412	284,406	638,715
Interest Expense, Net	24,811	9,029	43,187	21,220
Income (Loss) Before Income Taxes	(23,556)	247,383	241,219	617,495
Income Tax Provision (Benefit)	(6,850)	69,177	99,215	198,333
Net Income (Loss)	(16,706)	178,206	142,004	419,162
Preferred Stock Dividends	-	-	-	443
Net Income (Loss) Available to Common Stockholders	$ (16,706)	$ 178,206	$ 142,004	$ 418,719
Net Income (Loss) Per Share Available to				

Common Stockholders				
Basic	$ (0.07)	$ 0.72	$ 0.57	$ 1.70
Diluted	$ (0.07)	$ 0.71	$ 0.57	$ 1.67
Dividends Declared per Common Share	$ 0.145	$ 0.120	$ 0.290	$ 0.240
Average Number of Common Shares				
Basic	248,207	246,536	248,095	245,950
Diluted	248,207	251,135	250,499	250,553

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

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

	June 30, 2009	December 31, 2008
ASSETS		
Current Assets		
Cash and Cash Equivalents	$ 706,964	$ 331,311
Accounts Receivable, Net	570,262	722,695
Inventories	243,614	187,970
Assets from Price Risk Management Activities	606,595	779,483
Income Taxes Receivable	19,078	27,053
Other	63,763	59,939
Total	2,210,276	2,108,451
Property, Plant and Equipment		

Oil and Gas Properties (Successful Efforts Method)	22,292,107	20,803,629
Other Property, Plant and Equipment	1,172,546	1,057,888
Total Property, Plant and Equipment	23,464,653	21,861,517
Less: Accumulated Depreciation, Depletion and Amortization	(9,018,974)	(8,204,215)
Total Property, Plant and Equipment, Net	14,445,679	13,657,302
Other Assets	136,797	185,473
Total Assets	$16,792,752	$15,951,226

LIABILITIES AND STOCKHOLDERS' EQUITY

Current Liabilities		
Accounts Payable	$ 720,053	$ 1,122,209
Accrued Taxes Payable	78,470	86,265
Dividends Payable	35,983	33,461
Liabilities from Price Risk Management Activities	11,758	4,429
Deferred Income Taxes	213,413	368,231
Current Portion of Long-Term Debt	37,000	37,000
Other	92,943	113,321
Total	1,189,620	1,764,916
	2,760,000	1,860,000

Long-Term Debt		
Other Liabilities	550,339	498,291
Deferred Income Taxes	3,033,271	2,813,522
Commitments and Contingencies (Note 9)		
Stockholders' Equity		
Common Stock, $0.01 Par, 640,000,000 Shares Authorized and 250,528,510 Shares Issued at June 30, 2009 and 249,758,577 Shares Issued at December 31, 2008	202,505	202,498
Additional Paid in Capital	395,128	323,805
Accumulated Other Comprehensive Income	130,503	27,787
Retained Earnings	8,535,559	8,466,143
Common Stock Held in Treasury, 76,279 Shares at June 30, 2009 and 126,911 Shares at December 31, 2008	(4,173)	(5,736)
Total Stockholders' Equity	9,259,522	9,014,497
Total Liabilities and Stockholders'	$16,792,752	$15,951,226

Equity

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

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

	Six Months Ended June 30, 2009	Six Months Ended June 30, 2008
Cash Flows From Operating Activities		
Reconciliation of Net Income to Net Cash Provided by Operating Activities:		
Net Income	$ 142,004	$ 419,162
Items Not Requiring (Providing) Cash		
Depreciation, Depletion and Amortization	764,921	612,493
Impairments	112,517	81,449
Stock-Based Compensation Expenses	48,479	44,566
Deferred Income Taxes	62,161	123,330
Other, Net	1,689	(127,693)
Dry Hole Costs	36,637	15,213
Mark-to-Market Commodity Derivative Contracts		
Total (Gains) Losses	(384,953)	1,312,666
Realized Gains (Losses)	655,740	(114,859)
Other, Net	6,865	9,077
Changes in Components of		

Working Capital and Other Assets and Liabilities		
Accounts Receivable	149,021	(395,526)
Inventories	(22,151)	(9,176)
Accounts Payable	(414,823)	255,495
Accrued Taxes Payable	(17,743)	(92,738)
Other Assets	(7,487)	(61,623)
Other Liabilities	(24,842)	(8,440)
Changes in Components of Working Capital Associated with Investing and Financing Activities	169,183	(775)
Net Cash Provided by Operating Activities	1,277,218	2,062,621
Investing Cash Flows		
Additions to Oil and Gas Properties	(1,433,591)	(2,144,769)
Additions to Other Property, Plant and Equipment	(151,845)	(196,353)
Proceeds from Sales of Assets	828	354,413
Changes in Components of Working Capital Associated with Investing Activities	(169,101)	648
Other, Net	1,384	(20,429)
Net Cash Used in Investing Activities	(1,752,325)	(2,006,490)
Financing Cash Flows		

Long-Term Debt Borrowing	900,000	-
Long-Term Debt Repayments	-	(38,000)
Dividends Paid	(69,516)	(51,647)
Redemption of Preferred Stock	-	(5,395)
Excess Tax Benefits from Stock-Based Compensation	21,874	55,552
Treasury Stock Purchased	(6,125)	(6,865)
Proceeds from Stock Options Exercised and Employee Stock Purchase Plan	8,026	48,509
Debt Issuance Costs	(8,741)	-
Other, Net	(82)	127
Net Cash Provided by Financing Activities	845,436	2,281
Effect of Exchange Rate Changes on Cash	5,324	(4,542)
Increase in Cash and Cash Equivalents	375,653	53,870
Cash and Cash Equivalents at Beginning of Period	331,311	54,231
Cash and Cash Equivalents at End of Period	$ 706,964	$ 108,101

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 (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, 2008, filed on February 25, 2009 (EOG's 2008 Annual Report).

The preparation of financial statements in conformity with 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 six months ended June 30, 2009 are not necessarily indicative of the results to be expected for the full year.

Gathering, processing and marketing revenues represent sales of third-party natural gas, crude oil and natural gas liquids as well as gathering fees associated with gathering third-party natural gas. EOG's gathering, processing and marketing revenues were previously presented

net of related purchase and transportation costs in Net Operating Revenues - Other, Net. In addition, certain other expenses previously included in Lease and Well have been reclassified to Gathering and Processing Costs. The effect of these reclassifications on the three and six months ended June 30, 2008 presentation in the Consolidated Statements of Income was to increase total net operating revenues and total operating expenses by $63 million and $96 million, respectively. These changes did not impact previously reported operating income, net income or cash flows.

Recently Issued Accounting Standards and Developments. In June 2009, the Financial Accounting Standards Board (FASB) issued Statement of Financial Accounting Standards (SFAS) No. 168, "The *FASB Accounting Standards Codification™* and the Hierarchy of Generally Accepted Accounting Principles, a replacement of FASB Statement No. 162" (SFAS No. 168), which establishes the FASB Accounting Standards Codification Principles (Codification) as the source of authoritative accounting principles recognized by the FASB to be applied in the preparation of financial statements in conformity with GAAP. SFAS No. 168 explicitly recognizes rules and interpretive releases of the SEC under federal securities laws as authoritative GAAP for SEC registrants. SFAS No. 168 will become effective for interim and annual periods ending after September 15, 2009 and will result in disclosure modifications.

In May 2009, the FASB issued SFAS No. 165, "Subsequent Events" (SFAS No. 165). SFAS No. 165 clarifies that management must evaluate, as of each reporting period, events or transactions that occur after the balance sheet date and through the date that the financial statements are issued or available to be issued, both for interim and annual reporting periods. SFAS No. 165 is effective prospectively for interim and annual reporting periods ending after June 15, 2009 and will result in additional disclosures. EOG adopted the provisions of SFAS No. 165 effective April 1, 2009. See Note 14.

Effective January 1, 2009, EOG adopted SFAS No. 141 (revised 2007), "Business Combinations" (SFAS No. 141 (R)), which establishes principles and requirements for how the acquirer recognizes and measures in the financial statements the identifiable assets acquired, the liabilities assumed and any noncontrolling interest in the acquired, as well as determines what information to disclose to enable users of the financial statements to evaluate the nature and financial effects of the business combination.

In April 2009, the FASB issued FASB Staff Position (FSP) No. FAS 141 (R)-1, "Accounting for Assets Acquired and Liabilities Assumed in a Business Combination That Arise from Contingencies" (FSP 141 (R)-1). FSP 141 (R)-1 amended certain provisions of SFAS No. 141 (R) related to recognition, measurement and disclosure of assets acquired and liabilities assumed in a business combination that arise from contingencies. EOG adopted the provisions of FSP 141 (R)-1 effective January 1, 2009.

In April 2009, the FASB issued FSP FAS 107-1 and APB 28-1, "Interim Disclosures about Fair Value of Financial Instruments" (FSP 107-1), which amends SFAS No. 107, "Disclosures about Fair Value of Financial Instruments," to require disclosures about fair value of financial instruments for interim reporting periods as well as in annual financial statements. FSP 107-1 also amends Accounting Principles Board Opinion No. 28, "Interim Financial Reporting," to require those disclosures in summarized financial information at interim periods. FSP 107-1 is effective for interim periods ending after June 15, 2009. EOG adopted the provisions of FSP 107-1 at June 30, 2009. See Note 11.

In December 2008, the SEC released a final rule, "Modernization of Oil and Gas Reporting," which amends the oil and gas reporting requirements. The key revisions to the reporting requirements include: using a 12-month average price to determine reserves; including nontraditional resources in reserves if they are intended to be upgraded to synthetic oil and gas; ability to use new technologies to determine and estimate reserves; and permitting the disclosure of probable and possible reserves. In addition, the final rule includes the requirements to report the independence and qualifications of the reserve preparer or auditor; to file a report as an exhibit when a third party is relied upon to prepare reserve estimates or conduct reserve audits; and to disclose the development of any proved undeveloped reserves (PUDs), including the total quantity of PUDs at year-end, material changes to PUDs during the year, investments and progress toward the development of PUDs and an explanation of the reasons why material concentrations of PUDs have remained undeveloped for five years or more after disclosure as PUDs. The accounting changes resulting from changes in definitions and pricing assumptions should be treated as a change in accounting principle that is inseparable from a change in accounting estimate, which is to be applied prospectively. The final rule is effective for annual reports for fiscal years ending on or after December 31, 2009. Early adoption is not permitted. EOG is assessing the impact that this final rule will have on its financial statements.

In March 2008, the FASB issued SFAS No. 161, "Disclosures about Derivative Instruments and Hedging Activities - an amendment of FASB Statement No. 133" (SFAS No. 161). SFAS No. 161 does not change the scope or accounting of SFAS No. 133, "Accounting for Derivative Instruments and Hedging Activities," as amended (SFAS No. 133), but expands disclosure requirements about an entity's derivative instruments and hedging activities. SFAS No. 161 is effective for financial statements issued for fiscal years and interim periods beginning after November 15, 2008. EOG adopted the provisions of SFAS No. 161 effective January 1, 2009. See Note 13.

In September 2006, the FASB issued SFAS No. 157, "Fair Value Measurements" (SFAS No. 157). SFAS No. 157 provides a definition of fair value, establishes a framework for measuring fair value and expands disclosures about fair value measurements. The standard also requires additional disclosures on the use of fair value in measuring assets and liabilities. SFAS No. 157 establishes a fair value hierarchy and requires disclosure of fair value measurements within that hierarchy. In February 2008, the FASB issued a Staff Position on SFAS No. 157, FSP No. FAS 157-2, "Effective Date of FASB Statement No. 157" (FSP 157-2). FSP 157-2 delays the effective date of SFAS No. 157 for all nonrecurring fair value measurements of nonfinancial assets and nonfinancial liabilities until fiscal years beginning after November 15, 2008. EOG partially adopted SFAS No. 157 effective January 1, 2008 and adopted the provisions related to nonfinancial assets and liabilities effective January 1, 2009. See Note 12.

2. Stock-Based Compensation

As more fully discussed in Note 6 to the Consolidated Financial Statements included in EOG's 2008 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 June 30,		Six Months Ended June 30,	
	2009	2008	2009	2008
Lease and Well	$ 5.4	$ 4.1	$ 11.4	$ 8.5
Exploration Costs	4.9	4.4	10.1	8.4
General and Administrative	11.8	16.3	27.0	27.7
Total	$ 22.1	$ 24.8	$ 48.5	$ 44.6

The EOG Resources, Inc. 2008 Omnibus Equity Compensation Plan (2008 Plan) provides for grants of stock options, stock-settled stock appreciation rights (SARs), restricted stock, restricted stock units and other stock-based awards, up to an aggregate maximum of 6.0 million shares of common stock, plus shares underlying forfeited or cancelled grants under the prior stock plans. At June 30, 2009, approximately 3.9 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 was estimated using the Hull-White II binomial option pricing model. Stock-based compensation expense related to stock option, SAR and ESPP grants totaled $10.4 million and $8.9 million during the three months ended June 30, 2009 and 2008, respectively, and $19.1 million and $17.8 million during the six months ended June 30, 2009 and 2008, respectively.

Weighted average fair values and valuation assumptions used to value stock option, SAR and ESPP grants during the six-month periods ended June 30, 2009 and 2008 are as follows:

Stock Options/SARs	ESPP
Six Months Ended	Six Months Ended

	June 30,		June 30,	
	2009	2008	2009	2008
Weighted Average Fair Value of Grants	$ 26.59	$ 34.22	$ 25.78	$ 21.86
Expected Volatility	51.74%	33.47%	78.89%	31.67%
Risk-Free Interest Rate	1.09%	2.47%	0.25%	3.29%
Dividend Yield	0.9%	0.4%	1.0%	0.4%
Expected Life	4.8 yrs	4.4 yrs	0.5 yrs	0.5 yrs

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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.

EOG has suspended the ESPP, effective for the July 1, 2009 - December 31, 2009 offering period, due to an insufficient number of shares remaining available under the ESPP. Subject to stockholder approval of an amendment to the ESPP to increase the shares available under the ESPP at the 2010 Annual Meeting of Stockholders, EOG expects to resume the ESPP for the January 1, 2010 - June 30, 2010 offering period. The ESPP was originally approved by EOG's stockholders in 2001.

The following table sets forth stock option and SAR transactions for the six-month periods ended June 30, 2009 and 2008 (stock options and SARs in thousands):

	Six Months Ended June 30, 2009		Six Months Ended June 30, 2008	
	Number of Stock Options/SARs	Weighted Average Grant Price	Number of Stock Options/SARs	Weighted Average Grant Price
Outstanding at January 1	7,802	$ 52.56	9,373	$ 41.04
Granted	66	70.34	51	117.58
Exercised (1)	(191)	30.64	(1,937)	25.71
Forfeited	(59)	71.72	(64)	61.92
Outstanding at June 30 (2)	7,618	$ 53.11	7,423	$ 45.39

Vested or Expected to Vest (3)	7,391	$ 52.38		7,192	$ 44.79
Exercisable at June 30 (4)	4,660	$ 38.60		3,886	$ 30.04

(1) The total intrinsic value of stock options/SARs exercised for the six months ended June 30, 2009 and 2008 was $7 million and $176 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 June 30, 2009 and 2008 was $146 million and $637 million, respectively. At June 30, 2009 and 2008, the weighted average remaining contractual life was 4.1 years and 4.7 years, respectively.
(3) The total intrinsic value of stock options/SARs vested or expected to vest at June 30, 2009 and 2008 was $146 million and $621 million, respectively. At June 30, 2009 and 2008, the weighted average remaining contractual life was 4.1 years and 4.7 years, respectively.
(4) The total intrinsic value of stock options/SARs exercisable at June 30, 2009 and 2008 was $140 million and $393 million, respectively. At June 30, 2009 and 2008, the weighted average remaining contractual life was 3.5 years and 4.1 years, respectively.

At June 30, 2009, unrecognized compensation expense related to non-vested stock option and SAR grants totaled $60.4 million. This unrecognized expense will be amortized on a straight-line basis over a weighted average period of 2.1 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 $11.7 million and $15.9 million for the three months ended June 30, 2009 and 2008, respectively, and $29.4 million and $26.8 million for the six months ended June 30, 2009 and 2008, respectively.

The following table sets forth the restricted stock and restricted stock units transactions for the six-month periods ended June 30, 2009 and 2008 (shares and units in thousand):

	Six Months Ended June 30, 2009		Six Months Ended June 30, 2008	
		Weighted		Weighted

	Number of Shares and Units		Average Grant Date Fair Value	Number of Shares and Units		Average Grant Date Fair Value
Outstanding at January 1	3,048	$	70.24	3,000	$	50.61
Granted	686		49.30	374		125.06
Released (1)	(335)		25.61	(181)		21.43
Forfeited	(22)		79.53	(32)		66.47
Outstanding at June 30 (2)	3,377	$	70.35	3,161	$	60.91

(1) The total intrinsic value of restricted stock and restricted stock units released for both the six months ended June 30, 2009 and 2008 was $19 million. 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 June 30, 2009 and 2008 was $229 million and $415 million, respectively.

At June 30, 2009, unrecognized compensation expense related to restricted stock and restricted stock units totaled $125.5 million. Such unrecognized expense will be recognized on a straight-line basis over a weighted average period of 3.2 years.

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3. Earnings (Loss) Per Share

The following table sets forth the computation of Net Income (Loss) Per Share Available to Common Stockholders for the three-month and six-month periods ended June 30, 2009 and 2008 (in thousands, except per share data). For the three-month period ending June 30, 2009, 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 available to common stockholders.

	Three Months Ended June 30, 2009	Three Months Ended June 30, 2008	Six Months Ended June 30, 2009	Six Months Ended June 30, 2008
Numerator for Basic and Diluted Earnings Per Share -				
Net Income (Loss)	$ (16,706)	$ 178,206	$ 142,004	$ 419,162
Less: Preferred Stock	-	-	-	443

Dividends				
Net Income (Loss) Available to Common Stockholders	$ (16,706)	$ 178,206	$ 142,004	$ 418,719
Denominator for Basic Earnings Per Share -				
Weighted Average Shares	248,207	246,536	248,095	245,950
Potential Dilutive Common Shares -				
Stock Options/SARs	-	3,141	1,462	3,183
Restricted Stock and Restricted Stock Units	-	1,458	942	1,420
Denominator for Diluted Earnings Per Share -				
Adjusted Diluted Weighted Average Shares	248,207	251,135	250,499	250,553
Net Income (Loss) Per Share Available to Common Stockholders				
Basic	$ (0.07)	$ 0.72	$ 0.57	$ 1.70
Diluted	$ (0.07)	$ 0.71	$ 0.57	$ 1.67

The diluted earnings per share calculation excludes stock options, SARs, restricted stock and restricted stock units that were anti-dilutive. The excluded stock options and SARs totaled 7.7 million and 1.9 million for the three months ended June 30, 2009 and 2008, respectively, and 3.2 million and 3.3 million for the six months ended June 30, 2009 and 2008, respectively. For the quarter ended June 30, 2009, excluded restricted stock and restricted stock units totaled 3.4 million.

4. Supplemental Cash Flow Information

Cash paid for interest and income taxes for the six-month periods ended June 30, 2009 and 2008 was as follows (in thousands):

	Six Months Ended June 30,	
	2009	2008
Interest	$ 44,270	$ 23,780
Income Taxes	$ 26,162	$ 138,941

5. Comprehensive Income

The following table presents the components of EOG's comprehensive income for the three-month and six-month periods ended June 30, 2009 and 2008 (in thousands):

	Three Months Ended June 30,		Six Months Ended June 30,	
	2009	2008	2009	2008
Comprehensive Income				
Net Income (Loss)	$ (16,706)	$ 178,206	$ 142,004	$ 419,162
Other Comprehensive Income (Loss)				
Foreign Currency Translation Adjustments	150,251	15,813	98,963	(61,277)
Foreign Currency Swap Transaction	2,572	(1,983)	4,966	(2,957)
Income Tax Related to Foreign Currency Swap Transaction	(649)	494	(1,258)	733
Defined Benefit Pension and				

Postretirement Plans	36	35	70	70
Income Tax Related to Defined Benefit Pension and Postretirement Plans	(13)	(12)	(25)	(76)
Total	$135,491	$192,553	$244,720	$355,655

6. Segment Information

Selected financial information by reportable segment is presented below for the three-month and six-month periods ended June 30, 2009 and 2008 (in thousands):

	Three Months Ended June 30,		Six Months Ended June 30,	
	2009	2008	2009	2008
Net Operating Revenues				
United States	$719,714	$ 763,994	$1,722,618	$1,602,041
Canada	86,142	215,061	191,044	385,515
Trinidad	50,150	105,131	91,412	215,015
Other International (1)	5,033	11,326	14,174	26,959
Total	$861,039	$1,095,512	$2,019,248	$2,229,530
Operating Income (Loss)				
United States	$ (6,088)	$ 64,471	$ 255,630	$ 295,029
Canada	(10,787)	115,535	(8,398)	175,323
Trinidad	29,772	64,159	51,270	152,561
Other International (1)	(12,879)	(1,062)	(17,072)	910
Total	18	243,103	281,430	623,823
Reconciling Items				
	1,237	13,309	2,976	14,892

Other Income, Net				
Interest Expense, Net	24,811	9,029	43,187	21,220
Income (Loss) Before Income Taxes	$ (23,556)	$ 247,383	$ 241,219	$ 617,495

(1) Other International includes EOG's United Kingdom operations and, effective July 1, 2008, EOG's China operations.

Total assets by reportable segment are presented below at June 30, 2009 and December 31, 2008 (in thousands):

	At June 30, 2009	At December 31, 2008
Total Assets		
United States	$ 13,176,235	$ 12,668,763
Canada	2,594,455	2,421,979
Trinidad	792,787	735,387
Other International (1)	229,275	125,097
Total	$ 16,792,752	$ 15,951,226

(1) Other International includes EOG's United Kingdom operations and, effective July 1, 2008, EOG's 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 oil and gas properties pursuant to SFAS No. 143, "Accounting for Asset Retirement Obligations," for the six-month periods ended June 30, 2009 and 2008 (in thousands):

	Six Months Ended June 30, 2009	Six Months Ended June 30, 2008

Carrying Amount at Beginning of Period	$368,159	$211,124
Liabilities Incurred	15,415	15,246
Liabilities Settled	(10,502)	(13,795)
Accretion	10,690	5,801
Revisions [1]	(94)	5,217
Foreign Currency Translations	3,806	(2,242)
Carrying Amount at End of Period	$387,474	$221,351
Current Portion	$ 19,834	$ 5,318
Noncurrent Portion	$367,640	$216,033

(1) Revisions to asset retirement obligations 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 six-month period ended June 30, 2009 in accordance with FSP No. 19-1, "Accounting for Suspended Well Costs," are presented below (in thousands):

	Six Months Ended June 30, 2009
Balance at December 31, 2008	$ 85,255
Additions Pending the Determination of Proved Reserves	72,951
Reclassifications to Proved Properties	(9,540)
Charged to Dry Hole Costs	(11,971)
Foreign Currency Translations	5,328
Balance at June 30, 2009	$ 142,023

The following table provides an aging of suspended well costs at June 30, 2009 (in thousands, except well count):

		At June 30, 2009
Capitalized exploratory well costs that have been capitalized for a period less than one year	$	79,832
Capitalized exploratory well costs that have been capitalized for a period greater than one year		62,191 (1)
Total	$	142,023
Number of exploratory wells that have been capitalized for a period greater than one year		4

(1) Costs related to three shale projects in British Columbia, Canada (B.C.) ($41 million) and an outside operated, offshore Central North Sea project in the United Kingdom (U.K.) ($21 million). In the B.C. shale projects, further reserve evaluations will be made based on drilling and completion activities during 2009 and 2010. In addition, EOG is evaluating infrastructure alternatives for the B.C. shale projects. In the Central North Sea project, the operator submitted a field development plan to the U.K. Department of Energy and Climate Change during the fourth quarter of 2008. EOG is currently focused on securing an export route for production from the Central North Sea project.

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. In accordance with SFAS No. 5, "Accounting for Contingencies," 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 and Postretirement Benefits

Pension Plans.

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 six months ended June 30, 2009 and 2008, EOG's total costs recognized for these pension plans were $10.4 million and $9.7 million, respectively.

In addition, as more fully discussed in Note 6 to Consolidated Financial Statements included in EOG's 2008 Annual Report, EOG's Canadian, Trinidadian and United Kingdom subsidiaries maintain various pension and savings plans for most of their respective employees. For both the six months ended June 30, 2009 and 2008, combined contributions to these plans were $1.2 million.

Postretirement Plan.

EOG has postretirement medical and dental benefits in place for eligible United States and Trinidad employees and their eligible dependents. For the six months ended June 30, 2009, EOG's total contributions to these plans were approximately $69,000. The net periodic benefit costs recognized for the postretirement medical and dental plans were $0.4 million for both the six months ended June 30, 2009 and 2008.

11. Long-Term Debt and Common Stock

Long-Term Debt.

EOG utilizes commercial paper and short-term borrowings from uncommitted credit facilities, bearing market interest rates, for various corporate financing purposes. EOG had no outstanding borrowings from commercial paper or uncommitted credit facilities at June 30, 2009. The weighted average interest rates for commercial paper and uncommitted credit facility borrowings for the six months ended June 30, 2009 were 0.98% and 1.07%, respectively.

On May 21, 2009, EOG completed its public offering of $900 million aggregate principal amount of 5.625% Senior Notes due 2019 (Notes). Interest on the Notes is payable semi-annually in arrears on June 1 and December 1 of each year, beginning December 1, 2009. Net proceeds from the offering of approximately $891 million were used for general corporate purposes, including repayment of outstanding commercial paper borrowings.

EOG currently has a $1.0 billion unsecured Revolving Credit Agreement (Agreement) with domestic and foreign lenders. The Agreement matures on June 28, 2012. At June 30, 2009, there were no borrowings or letters of credit outstanding under the Agreement. Advances under the Agreement accrue interest based, at EOG's option, on either the London InterBank Offering Rate plus an applicable margin (Eurodollar rate) or the base rate of the Agreement's administrative agent. At June 30, 2009, the Eurodollar rate and applicable base rate, had there been any amounts borrowed under the Agreement, would have been 0.50% and 3.25%, respectively.

On May 11, 2009, EOG Resources Trinidad Limited, a wholly owned foreign subsidiary of EOG, amended its 3-year, $75 million Revolving Credit Agreement (Credit Agreement) to extend the scheduled maturity date of the remaining outstanding balance of $37 million from May 12, 2009 to May 12, 2010. Borrowings under the Credit Agreement accrue interest based, at EOG's option, on either the Eurodollar rate or the base rate of the Credit Agreement's administrative agent. The applicable Eurodollar rate at June 30, 2009 was 2.82%. The weighted average Eurodollar rate for the amount outstanding during the first six months of 2009 was 2.81%.

Fair Value of Long-Term Debt

. At June 30, 2009 and December 31, 2008, EOG had $2,797 million and $1,897 million, respectively, of long-term debt, which had estimated fair values of approximately $2,985 million and $1,933 million, respectively. The estimated fair value of long-term debt was based upon quoted market prices and, where such quotes were not available, upon interest rates available to EOG at period-end.

Common Stock.

On February 4, 2009, EOG's Board of Directors increased the quarterly cash dividend on EOG's common stock from the previous $0.135 per share to $0.145 per share effective with the dividend paid on April 30, 2009 to record holders as of April 16, 2009.

12. Fair Value Measurements

Certain of EOG's financial and nonfinancial assets and liabilities are reported at fair value in the accompanying balance sheets. Effective January 1, 2008, EOG adopted the provisions of SFAS No. 157, "Fair Value Measurements," for its financial assets and liabilities. SFAS No. 157 defines fair value, establishes a framework for measuring fair value and expands disclosures about fair value measurements. To increase consistency and comparability in fair value measurements and related disclosures, SFAS No. 157 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. SFAS No. 157 requires that an entity give consideration to the credit risk of its counterparties, as well as its own credit risk, when measuring financial assets and liabilities at fair value. In accordance with the provisions of FSP 157-2, "Effective Date of FASB Statement No. 157," EOG adopted the provisions of SFAS No. 157 relating to its nonfinancial assets and liabilities effective January 1, 2009.

The following table provides fair value measurement information within the hierarchy for certain of EOG's financial assets and liabilities carried at fair value on a recurring basis at June 30, 2009 and December 31, 2008 (in millions):

	Fair Value Measurements Using:		
	Quoted Prices in Active Markets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)
At June 30, 2009			
Financial Assets:			
Natural gas collars, price swaps and basis swaps	$ -	$ 607	$ -
Financial Liabilities:			
Natural gas collars, price swaps and basis swaps	$ -	$ 47	$ -
Foreign currency rate swap	$ -	$ 31	$ -
At December 31, 2008			
Financial Assets:			
Natural gas collars, price swaps			

and basis swaps	$	-	$	836	$	-
Financial Liabilities:						
Natural gas collars, price swaps and basis swaps	$	-	$	12	$	-
Foreign currency rate swap	$	-	$	26	$	-

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The estimated fair value of natural gas collar, price swap and basis swap contracts 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.

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 oil and gas properties. 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.

In accordance with the provisions of SFAS No. 144, "Accounting for the Impairment or Disposal of Long-Lived Assets," proved oil and gas properties with a carrying amount of $32 million were written down to their fair value of $9 million, resulting in a pretax impairment charge of $23 million for the six months ended June 30, 2009. 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.

13. Risk Management Activities

Effective January 1, 2009, EOG adopted the provisions of SFAS No. 161, "Disclosures about Derivative Instruments and Hedging Activities - an amendment of FASB Statement No. 133." SFAS No. 161 requires expanded disclosure about an entity's use of derivative instruments and the impact of those instruments on the Consolidated Statements of Income, Consolidated Balance Sheets and Consolidated Statements of Cash Flows. Information concerning EOG's derivative instruments and hedging activities is presented below.

Commodity Price Risk.

As more fully discussed in Note 11 to the Consolidated Financial Statements included in EOG's 2008 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. 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 (Losses) 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.

Foreign Currency Exchange Rate Risk.

As more fully described in Note 2 to the Consolidated Financial Statements included in EOG's 2008 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 principal amount of notes issued by one of EOG's Canadian subsidiaries. EOG accounts for the foreign currency swap transaction using the hedge accounting method, pursuant to the provisions of SFAS No. 133, "Accounting for Derivative Instruments and Hedging Activities," as amended. Changes in the fair value of the foreign currency swap do not impact Net Income (Loss) Available to Common Stockholders. The after-tax net impact from the foreign currency swap transaction was an increase in Other Comprehensive Income of $1.9 million and a reduction in Other Comprehensive Income of $1.5 million for the three months ended June 30, 2009 and 2008, respectively, and a $3.7 million increase and a $2.2 million reduction in Other Comprehensive Income for the six months ended June 30, 2009 and 2008, respectively (see Note 5).

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The following table sets forth the amount, on a gross basis, and classification of EOG's outstanding derivative financial instruments at June 30, 2009 and December 31, 2008. Certain amounts may be presented on a net basis in the financial statements in accordance with master netting arrangements between EOG and the counter-parties to the transactions (in millions):

		Fair Value at	
Description	Location on Balance Sheet	June 30, 2009	December 31, 2008
Asset Derivatives			
Natural gas collars and price swaps -			
Current portion	Assets from Price Risk Management Activities	$ 630	$ 786
Noncurrent portion	Other Assets	$ -	$ 63
Liability Derivatives			
Natural gas basis swaps -			
Current portion	Liabilities from Price Risk		

	Management Activities	$	35	$	11
Noncurrent portion	Other Liabilities	$	35	$	14
Foreign currency rate swaps -					
Noncurrent portion	Other Liabilities	$	31	$	26

EOG recognized a net gain on the mark-to-market of financial commodity derivative contracts of $385 million for the six months ended June 30, 2009 and a net loss of $1,313 million for the six months ended June 30, 2008.

Financial Collar Contracts.

Presented below is a comprehensive summary of EOG's natural gas financial collar contracts at June 30, 2009. The notional volumes are expressed in million British thermal units per day (MMBtud) and prices are expressed in dollars per million British thermal units ($/MMBtu). The average floor price of EOG's outstanding natural gas financial collar contracts for 2010 was $10.33 per million British thermal units (MMBtu) and the average ceiling price was $12.63 per MMBtu.

Natural Gas Financial Collar Contracts

		Floor Price		Ceiling Price	
	Volume (MMBtud)	Floor Range ($/MMBtu)	Weighted Average Price ($/MMBtu)	Ceiling Range ($/MMBtu)	Weighted Average Price ($/MMBtu)
2010					
January	40,000	$11.44 - 11.47	$11.45	$13.79 - 13.90	$13.85
February	40,000	11.38 - 11.41	11.40	13.75 - 13.85	13.80
March	40,000	11.13 - 11.15	11.14	13.50 - 13.60	13.55
April	40,000	9.40 - 9.45	9.42	11.55 - 11.65	11.60
May	40,000	9.24 - 9.29	9.26	11.41 - 11.55	11.48
June	40,000	9.31 - 9.36	9.34	11.49 - 11.60	11.55

On April 29, 2009, EOG settled its natural gas financial collar contracts with notional volumes of 40,000 MMBtud for the July 1, 2010 - December 31, 2010 period and received proceeds of $26.5 million.

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Financial Price Swap Contracts.

Presented below is a comprehensive summary of EOG's natural gas financial price swap contracts at June 30, 2009. The notional volumes are expressed in MMBtud and prices are expressed in $/MMBtu. The average price of EOG's outstanding natural gas financial price swap contracts for 2009 was $9.12 per MMBtu and for 2010 was $10.14 per MMBtu.

Natural Gas Financial Price Swap Contracts

	Volume (MMBtud)	Weighted Average Price ($/MMBtu)
2009		
January (closed)	585,000	$10.76
February (closed)	585,000	10.73
March (closed)	585,000	10.50
April (closed)	610,000	9.24
May (closed)	610,000	9.16
June (closed)	710,000	8.53
July (closed)	710,000	8.62
August	710,000	8.67
September	710,000	8.69
October	710,000	8.76
November	610,000	9.66
December	610,000	9.99
2010		
January	20,000	$11.20
February	20,000	11.15
March	20,000	10.89
April	20,000	9.29
May	20,000	9.13
June	20,000	9.21

On April 24, 2009, EOG settled its natural gas financial price swap contracts with notional volumes of 20,000 MMBtud for the July 1, 2010 - December 31, 2010 period and received proceeds of $12.1 million.

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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 has entered into 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 June 30, 2009. 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. 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)
2009		
Second Quarter (closed)	65,000	$(2.54)
Third Quarter (1)	65,000	(2.60)
Fourth Quarter	65,000	(3.03)
2010		
First Quarter	65,000	$(1.72)
Second Quarter	65,000	(2.56)
Third Quarter	65,000	(3.17)
Fourth Quarter	65,000	(3.73)
2011		
First Quarter	65,000	$(1.89)

(1) Includes closed contracts for July 2009.

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. 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 (ISDA) Master Agreements 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 ISDA 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 ISDA 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 June 30, 2009 and December 31, 2008. EOG had zero collateral posted at both June 30, 2009 and December 31, 2008.

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14. Subsequent Events

In June 2009, EOG entered into an agreement to acquire certain crude oil and natural gas properties and related assets located in Montague and Cooke Counties, Texas (Barnett Shale Combo Assets). The Barnett Shale Combo Assets consist of proved developed and undeveloped reserves and unproved acreage. The purchase price, which is subject to customary post-closing adjustments, totaled $134.1 million, consisting of cash consideration of $44.5 million and 1,450,000 shares of EOG common stock with a closing date fair market value of $89.6 million. The transaction closed on July 8, 2009.

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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 achieving a strong reinvestment rate of return, drilling internally generated prospects, delivering long-term production growth and maintaining a strong balance sheet.

United States and Canada.

EOG's effort to identify plays with larger 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 natural gas and crude oil production. Production in the United States and Canada accounted for approximately 86% of total company production in both the first six months of 2009 and the first six months of 2008. One of EOG's exploration strategies is to apply its horizontal drilling expertise gained in natural gas resources plays to unconventional oil reservoirs. During the first six months of 2009, the Fort Worth Basin Barnett Shale and North Dakota Bakken areas produced an increasing amount of crude oil and natural gas liquids as compared to the comparable period in 2008. For the first six months of 2009, crude oil and natural gas liquids production accounted for approximately 21% of total company production as compared to 17% for the comparable period in 2008. Based on current trends, EOG expects its 2009 crude oil and natural gas liquids production to continue to increase as compared to 2008. EOG's major producing areas are in Louisiana, New Mexico, North Dakota, Texas, Utah, Wyoming and western Canada.

In June 2009, EOG entered into an agreement to acquire certain crude oil and natural gas properties and related assets located in Montague and Cooke Counties, Texas (Barnett Shale Combo Assets). The Barnett Shale Combo Assets consist of proved developed and undeveloped reserves and approximately 25,000 net unproved acres. Production from these assets has averaged approximately 2,000 barrels equivalent per day, net. The purchase price, which is subject to customary post-closing adjustments, totaled $134.1 million, consisting of cash consideration of $44.5 million and 1,450,000 shares of EOG common stock with a closing date fair market value of $89.6 million. The transaction closed on July 8, 2009.

International

. In the United Kingdom, EOG drilled two operated exploratory wells in the East Irish Sea during the second quarter of 2009. The first exploratory well in Block 110/14d was unsuccessful. The second exploratory well in Block 110/12 resulted in an oil discovery. Additional drilling is planned for this block, in which EOG has a 100% working interest, in late 2009. In the Sichuan Basin, Sichuan Province, The People's Republic of China, EOG completed a monitoring well in the second quarter of 2009 and began drilling a horizontal well in June 2009.

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

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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. At June 30, 2009, EOG's debt-to-total capitalization ratio was 23% as compared to 17% at December 31, 2008. On May 21, 2009, EOG completed its public offering of $900 million aggregate principal amount of 5.625% Senior Notes due 2019 (Notes). Interest on the Notes is payable semi-annually in arrears on June 1 and December 1 of each year, beginning December 1, 2009. Net proceeds from the offering of approximately $891 million were used for general corporate purposes, including repayment of outstanding commercial paper borrowings. During the first six months of 2009, EOG funded $1.7 billion in exploration and development and other property, plant and equipment expenditures and paid $70 million in dividends to common stockholders, primarily by utilizing cash provided from its operating activities, proceeds from commercial paper and uncommitted credit facility borrowings and proceeds from the offering of the Notes.

For 2009, EOG's budget for exploration and development and other property, plant and equipment expenditures is approximately $3.3 billion, including acquisitions of approximately $140 million. United States and Canada natural gas and crude oil drilling activity continues to be a key component of these expenditures. EOG intends to manage the 2009 capital budget while maintaining a strong balance sheet. When it fits EOG's strategy, EOG will make acquisitions that bolster existing drilling programs or offer EOG incremental exploration and/or production opportunities. Management continues to believe EOG has one of the strongest prospect inventories in EOG's history.

Results of Operations

The following review of operations for the three and six months ended June 30, 2009 and 2008 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 June 30, 2009 vs. Three Months Ended June 30, 2008

Net Operating Revenues.

During the second quarter of 2009, net operating revenues decreased $235 million, or 21%, to $861 million from $1,096 million for the same period of 2008. Total wellhead revenues for the second quarter of 2009, which are revenues generated from sales of EOG's production of natural gas, crude oil and condensate and natural gas liquids, decreased $1,118 million, or 60%, to $747 million from $1,865 million for the same period of 2008. During the second quarter of 2009, EOG recognized a net gain on mark-to-market commodity derivative contracts of $34 million compared to a loss of $843 million for the same period of 2008. Gathering, processing and marketing revenues, which are revenues generated from sales of third-party natural gas, crude oil and natural gas liquids as well as gathering fees associated with gathering third-party natural gas, for the second quarter of 2009 increased $13 million, or 21%, to $77 million from $64 million for the same period of 2008.

Wellhead volume and price statistics for the three-month periods ended June 30, 2009 and 2008 were as follows:

	Three Months Ended June 30,	
	2009	2008
Natural Gas Volumes (MMcfd) (1)		
United States	1,139	1,139
Canada	225	215
Trinidad	266	217

Other International (2)	15	12
Total	1,645	1,583
Average Natural Gas Prices ($/Mcf) (3)		
United States	$ 3.37	$ 10.36
Canada	3.40	9.42
Trinidad	1.51	3.64
Other International (2)	3.55	9.95
Composite	3.07	9.31
Crude Oil and Condensate Volumes (MBbld) (1)		
United States	42.9	35.4
Canada	2.9	2.6
Trinidad	3.0	3.2
Other International (2)	0.1	-
Total	48.9	41.2
Average Crude Oil and Condensate Prices ($/Bbl) (3)		
United States	$52.82	$117.60
Canada	52.52	112.55
Trinidad	47.50	113.29
Other International (2)	46.75	114.40
Composite	52.47	116.94
Natural Gas Liquids Volumes (MBbld) (1)		

United States	22.1	14.2
Canada	1.0	0.9
Total	23.1	15.1
Average Natural Gas Liquids Prices ($/Bbl) (3)		
United States	$25.60	$ 63.62
Canada	25.60	66.39
Composite	25.60	63.78
Natural Gas Equivalent Volumes (MMcfed) (4)		
United States	1,529	1,437
Canada	249	236
Trinidad	284	236
Other International (2)	15	12
Total	2,077	1,921
Total Bcfe (4)	189.0	174.8

(1) Million cubic feet per day or thousand barrels per day, as applicable.
(2) Other International includes EOG's United Kingdom operations and, effective July 1, 2008, EOG's China operations.
(3) Dollars per thousand cubic feet or per barrel, as applicable.
(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.

Wellhead natural gas revenues for the second quarter of 2009 decreased $881 million, or 66%, to $460 million from $1,341 million for the same period of 2008. The decrease was due to a lower composite average wellhead natural gas price ($933 million), partially offset by increased natural gas deliveries ($52 million). EOG's composite average wellhead natural gas price decreased 67% to $3.07 per thousand cubic feet (Mcf) for the second quarter of 2009 from $9.31 per Mcf for the same period of 2008.

Natural gas deliveries for the second quarter of 2009 increased 62 MMcfd, or 4%, to 1,645 MMcfd from 1,583 MMcfd for the same period of 2008. The increase was primarily due to higher production in Trinidad (49 MMcfd) and Canada (10 MMcfd). The increase in Trinidad was primarily due to increased net contractual deliveries and reduced plant shutdowns for maintenance during 2009. The increase in Canada was primarily attributable to British Columbia Horn River Basin production.

Wellhead crude oil and condensate revenues for the second quarter of 2009 decreased $204 million, or 47%, to $233 million from $437 million for the same period of 2008, due to a lower composite average wellhead crude oil and condensate price ($287 million), partially offset by an increase of 8 MBbld, or 19%, in wellhead crude oil and condensate deliveries ($83 million). The increase in deliveries primarily reflects increased production in North Dakota. The composite average wellhead crude oil and condensate price for the second quarter of 2009 decreased 55% to $52.47 per barrel compared to $116.94 per barrel for the same period of 2008.

Natural gas liquids revenues for the second quarter of 2009 decreased $34 million, or 39%, to $54 million from $88 million for the same period of 2008, due to a lower composite average price ($80 million), partially offset by an increase of 8 MBbld, or 53%, in natural gas liquids deliveries ($46 million). The composite average natural gas liquids price for the second quarter of 2009 decreased 60% to $25.60 per barrel compared to $63.78 per barrel for the same period of 2008. The increase in deliveries primarily reflects increased volumes in the Fort Worth Basin Barnett Shale area.

During the second quarter of 2009, EOG recognized a net gain on mark-to-market financial commodity derivative contracts of $34 million compared to a loss of $843 million for the same period of 2008. During the second quarter of 2009, the net cash inflow related to settled natural gas financial collar, price swap and basis swap contracts was $345 million compared to the cash outflow related to settled natural gas and crude oil financial price swap contracts of $138 million for the same period of 2008.

Gathering, processing and marketing revenues represent sales of third-party natural gas, crude oil and natural gas liquids as well as gathering fees associated with gathering third-party natural gas. During the three months ended June 30, 2009 and 2008, substantially all of such revenues were related to sales of third-party natural gas and crude oil. Marketing costs represent the costs of purchasing third-party natural gas and crude oil and the associated transportation costs.

Gathering, processing and marketing revenues less marketing costs for the second quarter of 2009 were $2 million higher compared to the same period of 2008. The increase resulted primarily from increased natural gas marketing operations in the Gulf Coast area.

Operating and Other Expenses.

For the second quarter of 2009, operating expenses of $861 million were $9 million higher than the $852 million incurred in the second quarter of 2008. The following table presents the costs per thousand cubic feet equivalent (Mcfe) for the three-month periods ended June 30, 2009 and 2008:

	Three Months Ended June 30, 2009	Three Months Ended June 30, 2008
Lease and Well	$ 0.71	$ 0.74
	0.35	0.36

Transportation Costs		
Depreciation, Depletion and Amortization (DD&A) -		
Oil and Gas Properties	1.86	1.71
Other Property, Plant and Equipment	0.12	0.09
General and Administrative (G&A)	0.31	0.35
Interest Expense, Net	0.13	0.05
Total (1)	$ 3.48	$ 3.30

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

The primary factors impacting the cost components of per-unit rates of lease and well, transportation costs, DD&A, G&A and interest expense, net for the three months ended June 30, 2009 compared to the same period of 2008 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 costs of operations to restore or maintain production from existing wells.

Each of these categories of costs individually fluctuate 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.

Lease and well expenses of $135 million for the second quarter of 2009 increased $5 million from $130 million for the same prior year period primarily due to higher operating and maintenance expenses in the United States ($9 million) and Canada ($2 million), partially offset by changes in the Canadian exchange rate ($4 million) and decreased expenditures for workovers in the United States ($2 million).

Transportation costs represent costs incurred directly by EOG from third-party carriers 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 and transportation fees.

Transportation costs of $66 million for the second quarter of 2009 increased $3 million from $63 million for the same prior year period primarily due to increased production and costs associated with marketing arrangements to transport production from the Rocky Mountain area ($2 million) and the South Texas area ($2 million) to downstream markets.

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 natural gas gathering and processing facilities, compressors, vehicles, buildings and leasehold improvements, furniture and fixtures, and computer hardware and software.

DD&A expenses for the second quarter of 2009 increased $61 million to $376 million from $315 million for the same prior year period. DD&A expenses associated with oil and gas properties for the second quarter of 2009 were $53 million higher than the same prior year period primarily due to higher unit rates in the United States ($29 million), Trinidad ($3 million) and Canada ($3 million) and as a result of increased production in the United States ($16 million) and in Canada ($2 million), partially offset by changes in the Canadian exchange rate ($7 million).

DD&A expenses associated with other property, plant and equipment for the second quarter of 2009 were $8 million higher than the same prior year period primarily due to increased expenditures associated with natural gas gathering systems and processing plants in the Fort Worth Basin Barnett Shale area ($5 million) and Rocky Mountain area ($2 million).

G&A expenses of $59 million for the second quarter of 2009 decreased $3 million from the same prior year period primarily due to lower employee-related costs ($4 million), partially offset by higher insurance costs ($1 million).

Interest expense, net of $25 million for the second quarter of 2009 increased $16 million compared to the same prior year period primarily due to a higher average debt balance ($18 million), partially offset by higher capitalized interest ($2 million).

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

Gathering and processing costs for the second quarter of 2009 increased $5 million to $14 million as compared to the same prior year period primarily due to increased activities in the Rocky Mountain area ($3 million) and Fort Worth Basin Barnett Shale area ($1 million).

Exploration costs of $34 million for the second quarter of 2009 decreased $25 million from the same prior year period primarily due to decreased geological and geophysical expenditures in the United States ($22 million) and the United Kingdom ($3 million).

Impairments include amortization of unproved leases, as well as impairments under Statement of Financial Accounting Standards (SFAS) No. 144, "Accounting for the Impairment or Disposal of Long-Lived Assets" (SFAS No. 144), which requires an entity to compute impairments to the carrying value of long-lived assets based on future cash flow analysis. Impairments of $47 million for the second quarter of 2009 decreased $2 million from $49 million for the same prior year period primarily due to decreased SFAS No. 144 related impairments ($24 million), partially offset by increased amortization costs of unproved leases in the United States ($22 million). The decreased SFAS No. 144 related impairments is a result of no SFAS No. 144 related impairments recorded in the second quarter of 2009 and SFAS No. 144 related impairments recorded in the second quarter of 2008 in Trinidad as a result of EOG's relinquishment of its rights to Block Lower Reverse "L" (LRL) ($20 million) and in the United States ($4 million). Under SFAS No. 144, EOG recorded impairments of zero and $24 million for the second quarter of 2009 and 2008, respectively.

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

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Taxes other than income for the second quarter of 2009 decreased $72 million to $23 million (3.1% of wellhead revenues) from $95 million (5.1% of wellhead revenues) for the same prior year period. The decrease in taxes other than income was primarily due to a decrease in severance/production taxes as a result of decreased wellhead revenues in the United States ($43 million) and Trinidad ($5 million), an increase in credits taken in 2009 for Texas high cost gas severance tax rate reductions ($15 million) and lower ad valorem/property taxes in the United States ($13 million), partially offset by an increase in franchise taxes in the United States ($6 million). The decline in taxes other than income as a percentage of wellhead revenues primarily reflects an increase in credits taken in 2009 for Texas high cost gas severance tax rate reductions combined with a decline in non-revenue based taxes.

Other income, net was $1 million for the second quarter of 2009 compared to $13 million for the same prior year period. The decrease of $12 million was primarily due to lower equity income from ammonia plants in Trinidad ($6 million), lower interest income ($2 million) and settlements received related to the Enron Corp. bankruptcy in the second quarter of 2008 ($2 million).

EOG recognized an income tax benefit of $7 million for the second quarter of 2009 compared to an income tax provision of $69 million for the same prior year period. The change was primarily due to decreased pretax income ($95 million), partially offset by the absence of 2008 tax benefits related to the impairment of LRL ($18 million). The net effective tax rate for the second quarter of 2009 increased to 29% from 28% for the same prior year period.

Six Months Ended June 30, 2009 vs. Six Months Ended June 30, 2008

Net Operating Revenues.

During the first six months of 2009, net operating revenues decreased $211 million, or 9%, to $2,019 million from $2,230 million for the same period of 2008. Total wellhead revenues for the first six months of 2009 decreased $1,783 million, or 54%, to $1,515 million from $3,298 million for the same period of 2008. During the first six months of 2009, EOG recognized a net gain on mark-to-market financial commodity derivative contracts of $385 million compared to a net loss of $1,313 million for the same period of 2008. Gathering, processing and marketing revenues for the first six months of 2009 increased $15 million, or 15%, to $115 million from $100 million for the same period of 2008. Other, net operating revenues in 2008 primarily consist of a gain of $128 million on the sale of EOG's Appalachian assets in February 2008.

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Wellhead volume and price statistics for the six-month periods ended June 30, 2009 and 2008 were as follows:

	Six Months Ended June 30, 2009	2008
Natural Gas Volumes (MMcfd)		
United States	1,167	1,112
Canada	227	215
Trinidad	264	224
Other International	15	15
Total	1,673	1,566
Average Natural Gas Prices ($/Mcf)		
United States	$ 3.72	$ 9.23
Canada	3.92	8.42
Trinidad	1.42	3.76
Other International	4.84	9.89
Composite	3.39	8.34
Crude Oil and Condensate Volumes (MBbld)		
United States	43.8	33.0
Canada	3.1	2.5
Trinidad	3.0	3.4
Other International	0.1	-
Total	50.0	38.9
Average Crude Oil and Condensate Prices ($/Bbl)		
United States	$42.85	$105.78
Canada	44.53	101.41
Trinidad	40.49	99.92
	46.73	96.84

Other International		
Composite	42.82	104.97
Natural Gas Liquids Volumes (MBbld)		
United States	21.9	15.5
Canada	1.1	0.9
Total	23.0	16.4
Average Natural Gas Liquids Prices ($/Bbl)		
United States	$23.88	$ 60.19
Canada	25.56	61.52
Composite	23.96	60.26
Natural Gas Equivalent Volumes (MMcfed)		
United States	1,561	1,403
Canada	252	236
Trinidad	282	244
Other International	16	15
Total	2,111	1,898
Total Bcfe	382.1	345.4

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Wellhead natural gas revenues for the first six months of 2009 decreased $1,350 million, or 57%, to $1,028 million from $2,378 million for the same period of 2008. The decrease was due to a lower composite average wellhead natural gas price ($1,499 million), partially offset by increased natural gas deliveries ($149 million). EOG's composite average wellhead natural gas price decreased 59% to $3.39 per Mcf for the first six months of 2009 from $8.34 per Mcf for the same period of 2008.

Natural gas deliveries for the first six months of 2009 increased 107 MMcfd, or 7%, to 1,673 MMcfd from 1,566 MMcfd for the same period of 2008. The increase was due to higher production in the United States (55 MMcfd), Trinidad (40 MMcfd) and Canada (12 MMcfd). The increase in the United States was primarily attributable to increased production in Texas (44 MMcfd), the Rocky Mountain area (30 MMcfd) and Louisiana (2 MMcfd), partially offset by decreased production in Mississippi (8 MMcfd), Oklahoma (4 MMcfd), Pittsburgh as a result of the February 2008 sale of EOG's Appalachian assets (4 MMcfd) and New Mexico (4 MMcfd). The increase in Trinidad was primarily due to increased net contractual deliveries. The increase in Canada was primarily attributable to British Columbia Horn River Basin production.

Wellhead crude oil and condensate revenues for the first six months of 2009 decreased $352 million, or 48%, to $388 million from $740 million for the same period of 2008, due to a lower composite average wellhead crude oil and condensate price ($563 million), partially offset by an increase of 11 MBbld, or 29%, in wellhead crude oil and condensate deliveries ($211 million). The increase in deliveries primarily reflects increased production in North Dakota. The composite average wellhead crude oil and condensate price for the first six months of 2009 decreased 59% to $42.82 per barrel compared to $104.97 per barrel for the same period of 2008.

Natural gas liquids revenues for the first six months of 2009 decreased $80 million, or 44%, to $100 million from $180 million for the same period of 2008, due to a lower composite average price ($151 million), partially offset by an increase of 7 MBbld, or 40%, in natural gas liquids deliveries ($71 million). The composite average natural gas liquids price for the first six months of 2009 decreased 60% to $23.96 per barrel compared to $60.26 per barrel for the same period of 2008. The increase in deliveries primarily reflects increased volumes in the Fort Worth Basin Barnett Shale area.

During the first six months of 2009, EOG recognized a net gain on mark-to-market financial commodity derivative contracts of $385 million compared to a net loss of $1,313 million for the same period of 2008. During the first six months of 2009, the net cash inflow related to settled natural gas financial collar, price swap and basis swap contracts was $656 million compared to a net cash outflow related to settled natural gas and crude oil financial price swap contracts of $115 million for the same period of 2008.

Gathering, processing and marketing revenues less marketing costs for the first six months of 2009 increased $5 million to $9 million compared to $4 million for the same period of 2008. The increase resulted primarily from increased natural gas marketing operations in the Gulf Coast area.

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Operating and Other Expenses.

For the first six months of 2009, operating expenses of $1,738 million were $132 million higher than the $1,606 million incurred in the same period of 2008. The following table presents the costs per Mcfe for the six-month periods ended June 30, 2009 and 2008:

	Six Months Ended June 30, 2009	Six Months Ended June 30, 2008
Lease and Well	$ 0.73	$ 0.74
Transportation Costs	0.35	0.36
DD&A -		
Oil and Gas Properties	1.88	1.69
Other Property, Plant and Equipment	0.12	0.08
G&A	0.31	0.33
Interest Expense, Net	0.11	0.06
Total (1)	$ 3.50	$ 3.26

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

The primary factors impacting the cost components of per-unit rates of lease and well, transportation costs, DD&A and interest expense, net for the six months ended June 30, 2009 compared to the same period of 2008 are set forth below.

Lease and well expenses of $280 million for the first six months of 2009 increased $26 million from $254 million for the same prior year period primarily due to higher operating and maintenance expenses in the United States ($27 million) and Canada ($6 million) and higher lease and well administrative expenses ($3 million), partially offset by changes in the Canadian exchange rate ($11 million).

Transportation costs of $135 million for the first six months of 2009 increased $10 million from $125 million for the same prior year period primarily due to increased production and costs associated with marketing arrangements to transport production from the Rocky Mountain area ($6 million) and the Fort Worth Basin Barnett Shale area ($5 million) to downstream markets.

DD&A expenses for the first six months of 2009 increased $153 million to $765 million from $612 million for the same prior year period. DD&A expenses associated with oil and gas properties for the second quarter of 2009 were $135 million higher than the same prior year period primarily due to higher unit rates in the United States ($74 million), Canada ($8 million) and Trinidad ($7 million) and as a result of increased production in the United States ($51 million), Canada ($6 million) and in Trinidad ($2 million), partially offset by changes in the Canadian exchange rate ($18 million).

DD&A expenses associated with other property, plant and equipment for the second quarter of 2009 were $18 million higher than the same prior year period primarily due to increased expenditures associated with natural gas gathering systems and processing plants in the Fort Worth Basin Barnett Shale area ($10 million) and Rocky Mountain area ($5 million).

Interest expense, net of $43 million for the first six months of 2009 increased $22 million compared to the same prior year period primarily due to higher average debt balance ($28 million), partially offset by higher capitalized interest ($5 million).

Gathering and processing costs for the first six months of 2009 increased $14 million to $31 million as compared to the same prior year period primarily due to increased activities in the Rocky Mountain area ($8 million) and the Fort Worth Basin Barnett Shale area ($5 million).

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Exploration costs of $84 million for the first six months of 2009 decreased $24 million compared to the same prior year period primarily due to decreased geological and geophysical expenditures in the United States ($21 million) and the United Kingdom ($2 million).

Impairments of $113 million for the first six months of 2009 increased $31 million compared to the same prior year period primarily due to increased amortization of unproved leases in the United States ($41 million) and increased SFAS No. 144 related impairments in the United States ($13 million), partially offset by a SFAS No. 144 related impairment in Trinidad recorded in the second quarter of 2008 as a result of EOG's relinquishment of its rights to LRL ($20 million). Under SFAS No. 144, EOG recorded impairments of $23 million and $33 million for the six months ended June 30, 2009 and 2008, respectively.

Taxes other than income for the first six months of 2009 decreased $111 million to $71 million (4.7% of wellhead revenues) from $182 million (5.5% of wellhead revenues) for the same prior year period. The decrease in taxes other than income was primarily due to decreased severance/production taxes primarily as a result of decreased wellhead revenues in the United States ($71 million) and Trinidad ($12 million), an increase in credits taken in 2009 for Texas high cost gas severance tax rate reductions ($20 million) and lower ad valorem/property taxes in the United States ($12 million), partially offset by an increase in franchise taxes in the United States ($6 million). The decline in taxes other than income as a percentage of wellhead revenues primarily reflects an increase in credits taken in 2009 for Texas high cost gas severance tax rate reductions combined with a decline in non-revenue based taxes.

Other income, net was $3 million for the first six months of 2009 compared to $15 million for the same prior year period. The decrease of $12 million was primarily due to lower equity income from ammonia plants in Trinidad ($10 million), lower interest income ($3 million) and settlements received related to the Enron Corp. bankruptcy in the second quarter of 2008 ($2 million), partially offset by increased foreign currency transaction gains ($3 million).

Income tax provision of $99 million for the first six months of 2009 decreased $99 million compared to $198 million for the same prior year period due primarily to decreased pretax income ($132 million), partially offset by a higher effective tax rate. The net effective tax rate for the first six months of 2009 increased to 41% from 32% for the same prior year period primarily as a result of higher state taxes and the absence of 2008 tax benefits related to the impairment of LRL.

Capital Resources and Liquidity

Cash Flow.

The primary sources of cash for EOG during the six months ended June 30, 2009 were funds generated from operations, net commercial paper and uncommitted credit facility borrowings and a long-term debt borrowing. The primary uses of cash were funds used in operations; exploration and development expenditures; other property, plant and equipment expenditures; and dividend payments to stockholders. During the first six months of 2009, EOG's cash balance increased $376 million to $707 million from $331 million at December 31, 2008.

Net cash provided by operating activities of $1,277 million for the first six months of 2009 decreased $785 million compared to the same period of 2008 primarily reflecting a decrease in wellhead revenues ($1,783 million) and an increase in cash paid for interest expense ($20 million), partially offset by a favorable change in net cash flow from the settlement of financial commodity derivative contracts ($771 million), a decrease in net cash paid for income taxes ($113 million), a decrease in cash operating expenses ($88 million) and favorable changes in working capital and other assets and liabilities ($69 million).

Net cash used in investing activities of $1,752 million for the first six months of 2009 decreased by $254 million compared to the same period of 2008 due primarily to a decrease in additions to oil and gas properties ($711 million) and a decrease in additions to other property, plant and equipment ($45 million), partially offset by a decrease in proceeds from sales of assets ($354 million), primarily reflecting net proceeds from the sale of EOG's Appalachian assets in February 2008, and unfavorable changes in working capital associated with investing activities ($170 million).

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Net cash provided by financing activities was $845 million for the first six months of 2009 compared to $2 million for the same period of 2008. Cash provided by financing activities for the first six months of 2009 included a long-term debt borrowing ($900 million), excess tax benefits from stock-based compensation ($22 million) and proceeds from stock options exercised and employee stock purchase plan activity ($8 million). Cash used by financing activities for the first six months of 2009 included cash dividend payments ($70 million), debt issuance costs ($9 million) and the purchase of treasury stock ($6 million).

Total Expenditures.

For 2009, EOG's budget for exploration and development and other property, plant and equipment expenditures is approximately $3.3 billion, including acquisitions of approximately $140 million. The table below sets out components of total expenditures for the six-month periods ended June 30, 2009 and 2008 (in millions):

	Six Months Ended June 30,