CABOT OIL & GAS CORP
Form 10-Q
July 30, 2010
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UNITED STATES

SECURITIES AND EXCHANGE COMMISSION

WASHINGTON, D.C. 20549

FORM 10-Q

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

For the quarterly period ended June 30, 2010

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

Commission file number 1-10447

CABOT OIL & GAS CORPORATION

(Exact name of registrant as specified in its charter)

DELAWARE	**04-3072771**
(State or other jurisdiction of incorporation or organization)	**(I.R.S. Employer Identification Number)**

Three Memorial City Plaza

840 Gessner Road, Suite 1400, Houston, Texas 77024

(Address of principal executive offices including ZIP code)

(281) 589-4600

(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 and (2) has been subject to such filing requirements for the past 90 days. Yes x 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 x 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. (Check one):

Large accelerated filer x	Accelerated filer ¨	Non-accelerated filer ¨ (Do not check if a smaller reporting company)	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 x

As of July 26, 2010, there were 104,135,398 shares of Common Stock, Par Value $.10 Per Share, outstanding.

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PART I. FINANCIAL INFORMATION

ITEM 1. Financial Statements

CABOT OIL & GAS CORPORATION

CONDENSED CONSOLIDATED STATEMENT OF OPERATIONS (Unaudited)

(In thousands, except per share amounts)	Three Months Ended June 30, 2010	Three Months Ended June 30, 2009	Six Months Ended June 30, 2010	Six Months Ended June 30, 2009
OPERATING REVENUES				
Natural Gas Production	**$ 159,761**	$ 176,213	**$ 325,842**	$ 360,735
Brokered Natural Gas	**13,348**	11,704	**38,221**	45,085
Crude Oil and Condensate	**21,211**	16,210	**41,193**	30,452
Other	**1,154**	697	**2,774**	2,491
	195,474	204,824	**408,030**	438,763
OPERATING EXPENSES				
Brokered Natural Gas Cost	**11,793**	10,684	**33,061**	40,433
Direct Operations - Field and Pipeline	**24,347**	23,073	**47,330**	48,552
Taxes Other Than Income	**11,841**	10,914	**22,646**	23,812
Exploration	**10,233**	10,397	**18,659**	16,863
Depreciation, Depletion and Amortization	**67,687**	55,108	**125,962**	110,893
Impairment of Unproved Properties	**9,039**	6,730	**24,262**	16,037
General and Administrative	**12,853**	17,117	**28,599**	34,182
	147,793	134,023	**300,519**	290,772
Gain / (Loss) on Sale of Assets	**4,387**	(16,562)	**5,146**	(3,855)
INCOME FROM OPERATIONS	**52,068**	54,239	**112,657**	144,136
Interest Expense and Other	**15,769**	15,046	**30,681**	29,272
Income Before Income Taxes	**36,299**	39,193	**81,976**	114,864
Income Tax Expense	**14,617**	13,691	**31,598**	41,782
NET INCOME	**$ 21,682**	$ 25,502	**$ 50,378**	$ 73,082
Basic Earnings Per Share	**$ 0.21**	$ 0.25	**$ 0.49**	$ 0.71
Diluted Earnings Per Share	**$ 0.21**	$ 0.24	**$ 0.48**	$ 0.70
Weighted-Average Common Shares Outstanding	**103,915**	103,640	**103,855**	103,581
Diluted Common Shares (Note 5)	**104,964**	104,815	**104,838**	104,312
Dividends per Common Share	$ 0.03	$ 0.03	$ 0.06	$ 0.06

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

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CABOT OIL & GAS CORPORATION

CONDENSED CONSOLIDATED BALANCE SHEET (Unaudited)

(In thousands, except share amounts)	June 30, 2010	December 31, 2009
ASSETS		
Current Assets		
Cash and Cash Equivalents	**$ 47,685**	$ 40,158
Accounts Receivable, Net (Note 3)	**79,162**	80,362
Income Taxes Receivable	**3,767**	8,909
Inventories (Note 3)	**23,534**	27,990
Derivative Contracts (Note 7)	**85,773**	114,686
Other Current Assets (Note 3)	**8,336**	9,397
Total Current Assets	**248,257**	281,502
Properties and Equipment, Net (Successful Efforts Method) (Note 2)	**3,571,349**	3,358,199
Derivative Contracts (Note 7)	**3,629**	
Investment in Equity Securities (Note 2)	**20,636**	20,636
Other Assets (Note 3)	**26,329**	23,064
	$ 3,870,200	$ 3,683,401
LIABILITIES AND STOCKHOLDERS EQUITY		
Current Liabilities		
Accounts Payable (Note 3)	**$ 152,035**	$ 215,588
Deferred Income Taxes	**25,516**	35,104
Accrued Liabilities (Note 3)	**49,282**	58,049
Total Current Liabilities	**226,833**	308,741
Long-Term Liability for Pension and Postretirement Benefits	**48,931**	54,835
Long-Term Debt (Note 4)	**1,015,000**	805,000
Deferred Income Taxes	**675,824**	644,801
Other Liabilities (Note 3)	**57,708**	57,510
Total Liabilities	**2,024,296**	1,870,887
Commitments and Contingencies (Note 6)		
Stockholders Equity		
Common Stock:		
Authorized 240,000,000 Shares of $0.10 Par Value in 2010 and 2009 Issued 104,135,009 Shares and 103,856,447 Shares in 2010 and 2009, respectively	**10,414**	10,386
Additional Paid-in Capital	**709,954**	705,569
Retained Earnings	**1,101,622**	1,057,472
Accumulated Other Comprehensive Income (Note 9)	**27,263**	42,436
Less Treasury Stock, at Cost:		
202,200 Shares in 2010 and 2009, respectively	**(3,349)**	(3,349)
Total Stockholders Equity	**1,845,904**	1,812,514
	$ 3,870,200	$ 3,683,401

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

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CABOT OIL & GAS CORPORATION

CONDENSED CONSOLIDATED STATEMENT OF CASH FLOWS (Unaudited)

(In thousands)	Six Months Ended June 30, 2010	2009
CASH FLOWS FROM OPERATING ACTIVITIES		
Net Income	**$ 50,378**	$ 73,082
Adjustments to Reconcile Net Income to Cash Provided by Operating Activities:		
Depreciation, Depletion and Amortization	**125,962**	110,893
Impairment of Unproved Properties	**24,262**	16,037
Deferred Income Tax Expense	**29,091**	38,252
(Gain) / Loss on Sale of Assets	**(5,146)**	3,855
Exploration Expense	**8,426**	16,863
Unrealized Loss / (Gain) on Derivatives	**(355)**	(815)
Stock-Based Compensation Expense and Other	**8,355**	13,513
Changes in Assets and Liabilities:		
Accounts Receivable, Net	**1,200**	55,092
Income Taxes Receivable	**5,083**	
Inventories	**4,456**	16,163
Other Current Assets	**1,061**	(65)
Accounts Payable and Accrued Liabilities	**(5,937)**	(41,894)
Income Taxes Payable		3,441
Other Assets and Liabilities	**(3,658)**	(4,032)
Net Cash Provided by Operating Activities	**243,178**	300,385
CASH FLOWS FROM INVESTING ACTIVITIES		
Capital Expenditures	**(454,143)**	(309,833)
Proceeds from Sale of Assets	**16,742**	79,667
Net Cash Used in Investing Activities	**(437,401)**	(230,166)
CASH FLOWS FROM FINANCING ACTIVITIES		
Borrowings from Debt	**210,000**	70,000
Repayments of Debt		(122,000)
Dividends Paid	**(6,228)**	(6,213)
Capitalized Debt Issuance Costs	**(1,986)**	(10,409)
Other	**(36)**	150
Net Cash Provided by / (Used in) Financing Activities	**201,750**	(68,472)
Net Increase in Cash and Cash Equivalents	**7,527**	1,747
Cash and Cash Equivalents, Beginning of Period	**40,158**	28,101
Cash and Cash Equivalents, End of Period	**$ 47,685**	$ 29,848

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

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CABOT OIL & GAS CORPORATION

NOTES TO THE CONDENSED CONSOLIDATED FINANCIAL STATEMENTS (Unaudited)

1. FINANCIAL STATEMENT PRESENTATION

During interim periods, Cabot Oil & Gas Corporation (the Company) follows the same accounting policies used in its Annual Report on Form 10-K for the year ended December 31, 2009 (Form 10-K) filed with the Securities and Exchange Commission (SEC). The interim financial statements should be read in conjunction with the notes to the consolidated financial statements and information presented in the Form 10-K. In management s opinion, the accompanying interim condensed consolidated financial statements contain all material adjustments, consisting only of normal recurring adjustments, necessary for a fair statement. The results for any interim period are not necessarily indicative of the expected results for the entire year.

Certain reclassifications have been made to prior year statements to conform to the current year presentation. These reclassifications have no impact on net income.

In 2009, the Company restructured its operations by combining the Rocky Mountain and Appalachian areas to form the North region and by combining the Anadarko Basin with its Texas and Louisiana areas to form the South region. Certain prior year amounts have been reclassified to reflect this reorganization. Additionally, the Company exited Canada through the sale of its reserves. Prior to the third quarter of 2009, the Company presented the geographic areas as East, Gulf Coast, West and Canada.

With respect to the unaudited financial information of the Company as of June 30, 2010 and for the three and six months ended June 30, 2010 and 2009, PricewaterhouseCoopers LLP reported that they have applied limited procedures in accordance with professional standards for a review of such information. However, their separate report dated July 30, 2010 appearing herein states that they did not audit and they do not express an opinion on that unaudited financial information. Accordingly, the degree of reliance on their report on such information should be restricted in light of the limited nature of the review procedures applied. PricewaterhouseCoopers LLP is not subject to the liability provisions of Section 11 of the Securities Act of 1933 for their report on the unaudited financial information because that report is not a report or a part of the registration statement prepared or certified by PricewaterhouseCoopers LLP within the meaning of Sections 7 and 11 of the Act.

Recently Adopted Accounting Standards

In February 2010, the Financial Accounting Standards Board (FASB) issued Accounting Standards Update (ASU) No. 2010-09, Subsequent Events, which amends Accounting Standards Codification (ASC) 855 to eliminate the requirement to disclose the date through which management has evaluated subsequent events in the financial statements. ASU No. 2010-09 was effective upon issuance and its adoption had no impact on the Company s financial position, results of operations or cash flows.

Effective January 1, 2010, the Company partially adopted the provisions of FASB ASU No. 2010-06, Improving Disclosures about Fair Value Measurements, which amends ASC 820-10-50 to require new disclosures concerning (1) transfers into and out of Levels 1 and 2 of the fair value measurement hierarchy, and (2) activity in Level 3 measurements. In addition, ASU No. 2010-06 clarifies certain existing disclosure requirements regarding the level of disaggregation and inputs and valuation techniques and makes conforming amendments to the guidance on employers disclosures about postretirement benefit plans assets. The requirements to disclose separately purchases, sales, issuances, and settlements in the Level 3 reconciliation are effective for fiscal years beginning after December 15, 2010 (and for interim periods within such years). Accordingly, the Company will apply the disclosure requirements relative to the Level 3 reconciliation in the first quarter of 2011. There was no impact on the Company s financial position, results of operations or cash flows as a result of the partial adoption of ASU No. 2010-06. For further information, please refer to Note 8.

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CABOT OIL & GAS CORPORATION

NOTES TO THE CONDENSED CONSOLIDATED FINANCIAL STATEMENTS (Unaudited) (Continued)

2. PROPERTIES AND EQUIPMENT, NET

Properties and equipment, net are comprised of the following:

(In thousands)	June 30, 2010	December 31, 2009
Unproved Oil and Gas Properties	**$ 465,979**	$ 423,373
Proved Oil and Gas Properties	**4,357,770**	4,118,005
Gathering and Pipeline Systems	**306,815**	294,755
Land, Building and Other Equipment	**81,747**	77,474
	5,212,311	4,913,607
Accumulated Depreciation, Depletion and Amortization	**(1,640,962)**	(1,555,408)
	$ 3,571,349	$ 3,358,199

At June 30, 2010, the Company did not have any projects that had exploratory well costs that were capitalized for a period of greater than one year after drilling.

In April 2009, the Company sold substantially all of its Canadian properties to a private Canadian company. Total consideration received from the sale was $84.4 million, consisting of $64.3 million in cash and $20.1 million in common stock of a privately held Canadian company (included on the Condensed Consolidated Balance Sheet as Investment in Equity Securities at June 30, 2010 and December 31, 2009). The common stock investment is being accounted for using the cost method. The total net book value of the Canadian properties sold was $95.0 million.

The Company recognized a $3.9 million aggregate loss on sale of assets in the first half of 2009. The Company recorded a $10.5 million loss on sale of assets in the second quarter of 2009, primarily due to the sale of the Canadian properties described above. The Company recognized a $12.7 million gain on sale of assets in the first quarter of 2009 primarily related to the sale of the Thornwood properties in the North region. Cash proceeds of $11.4 million were received from the sale of the Thornwood properties.

In June 2010, the Company sold its Woodford shale prospect located in Oklahoma to Continental Resources Inc. The Company received approximately $15.9 million in cash proceeds and recognized a $10.3 million gain on sale of assets.

In June 2010, primarily as a result of the Company s decision to divest of certain oil and gas properties, an impairment loss of approximately $5.8 million was recognized related to the assets held for sale. The impairment charge is included in Gain / (Loss) on Sale of Assets in the Condensed Consolidated Statement of Operations. The net book value of these properties at June 30, 2010 was approximately $3.0 million, which approximates fair value. The fair value was determined using a market approach which considered the execution of a purchase and sale agreement the Company entered into on June 30, 2010. Accordingly, the inputs associated with the fair value of assets held for sale was considered level 2 in the fair value hierarchy.

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CABOT OIL & GAS CORPORATION

NOTES TO THE CONDENSED CONSOLIDATED FINANCIAL STATEMENTS (Unaudited) (Continued)

3. ADDITIONAL BALANCE SHEET INFORMATION

Certain balance sheet amounts are comprised of the following:

(In thousands)	June 30, 2010	December 31, 2009
ACCOUNTS RECEIVABLE, NET		
Trade Accounts	**$ 72,365**	$ 78,656
Joint Interest Accounts	**9,015**	3,564
Other Accounts	**1,774**	1,756
	83,154	83,976
Allowance for Doubtful Accounts	**(3,992)**	(3,614)
	$ 79,162	$ 80,362
INVENTORIES		
Natural Gas in Storage	**$ 10,333**	$ 14,434
Tubular Goods and Well Equipment	**12,517**	14,420
Pipeline Imbalances	**684**	(864)
	$ 23,534	$ 27,990
OTHER CURRENT ASSETS		
Drilling Advances	**$ 3,840**	$ 3,417
Prepaid Balances	**4,496**	5,980
	$ 8,336	$ 9,397
OTHER ASSETS		
Rabbi Trust Deferred Compensation Plan	**$ 13,441**	$ 10,031
Deferred Charges for Credit Agreements	**11,471**	11,621
Other Accounts	**1,417**	1,412
	$ 26,329	$ 23,064
ACCOUNTS PAYABLE		
Trade Accounts	**$ 19,510**	$ 17,434
Natural Gas Purchases	**7,075**	3,558
Royalty and Other Owners	**40,812**	40,080
Capital Costs	**70,807**	141,122
Taxes Other Than Income	**4,058**	4,267
Drilling Advances	**541**	864
Wellhead Gas Imbalances	**5,255**	4,140
Other Accounts	**3,977**	4,123
	$ 152,035	$ 215,588

ACCRUED LIABILITIES		
Employee Benefits	**$ 5,411**	$ 11,222
Current Liability for Pension Benefits	**488**	488
Current Liability for Postretirement Benefits	**981**	981
Taxes Other Than Income	**19,677**	22,780
Interest Payable	**20,923**	20,205
Derivative Contracts		425
Other Accounts	**1,802**	1,948
	$ 49,282	$ 58,049
OTHER LIABILITIES		
Rabbi Trust Deferred Compensation Plan	**$ 19,727**	$ 19,087
Accrued Plugging and Abandonment Liability	**30,488**	29,676
Derivative Contracts	**1,599**	1,954
Other Accounts	**5,894**	6,793
	$ 57,708	$ 57,510

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CABOT OIL & GAS CORPORATION

NOTES TO THE CONDENSED CONSOLIDATED FINANCIAL STATEMENTS (Unaudited) (Continued)

4. LONG-TERM DEBT

The Company s debt consisted of the following:

(In thousands)	June 30, 2010	December 31, 2009
Long-Term Debt		
7.33% Weighted-Average Fixed Rate Notes	**$ 170,000**	$ 170,000
6.51% Weighted-Average Fixed Rate Notes	**425,000**	425,000
9.78% Notes	**67,000**	67,000
Credit Facility	**353,000**	143,000
	$ 1,015,000	$ 805,000

In April 2009, the Company entered into a new revolving credit facility and terminated its prior credit facility. The credit facility provides for an available credit line of $500 million and contains an accordion feature allowing the Company to increase the available credit line to $600 million, if any one or more of the existing banks or new banks agree to provide such increased commitment amount. The credit facility also provides for the issuance of letters of credit, which would reduce the Company s borrowing capacity. In June 2010, the Company amended the facility to provide that the Company s asset coverage ratio under the facility would be calculated in accordance with agreements governing its senior notes, as such agreements may be amended from time to time. Under the credit facility, the Company is currently required to maintain an asset coverage ratio of the present value of the Company s proved reserves plus working capital to debt of 1.75:1. The term of the facility expires in April 2012.

In June 2010, the Company amended the agreements governing its senior notes to amend the required asset coverage ratio (the present value of the Company s proved reserves plus working capital to debt) contained in the agreements. The amendments revised the calculation of present value of proved reserves to reflect specified pricing assumptions based on quoted futures prices in lieu of historical realized prices, reduced the limit on proved undeveloped reserves included in the calculation from 35% to 30%, and increased the required ratio to 1.75:1 from 1.50:1. The amendments also provided that for so long as a borrowing base calculation is required under the Company s credit facility, the calculated indebtedness may not exceed 115% of such borrowing base for this ratio. If such a borrowing base calculation is not required under the credit facility, the Company would no longer be subject to the asset coverage ratio under the agreements, but would instead be required to maintain a ratio of debt to consolidated EBITDAX (as defined) not to exceed 3.0 to 1.0. In conjunction with the amendments, the Company incurred $2.0 million of debt issuance costs which were capitalized and are being amortized over the term of the respective amended agreements in accordance with ASC 470-50, Debt Modifications and Extinguishments.

The Company believes it is in compliance in all material respects with its debt covenants.

At June 30, 2010, the Company had $353.0 million of borrowings outstanding under its revolving credit facility at a weighted-average interest rate of 3.75% and $146.0 million available for future borrowings. In addition, the Company had letters of credit outstanding at June 30, 2010 of $1.0 million.

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CABOT OIL & GAS CORPORATION

NOTES TO THE CONDENSED CONSOLIDATED FINANCIAL STATEMENTS (Unaudited) (Continued)

5. EARNINGS PER COMMON SHARE

Basic EPS is computed by dividing net income (the numerator) by the weighted-average number of common shares outstanding for the period (the denominator). Diluted EPS is similarly calculated except that the denominator is increased using the treasury stock method to reflect the potential dilution that could occur if outstanding stock options and stock appreciation rights were exercised and stock awards were vested at the end of the applicable period.

The following is a calculation of basic and diluted weighted-average shares outstanding for the three and six months ended June 30, 2010 and 2009:

(In thousands)	Three Months Ended June 30, 2010	Three Months Ended June 30, 2009	Six Months Ended June 30, 2010	Six Months Ended June 30, 2009
Weighted-Average Shares Basic	**103,915**	103,640	**103,855**	103,581
Dilution Effect of Stock Options, Stock Appreciation Rights and Stock Awards at End of Period	**1,049**	1,175	**983**	731
Weighted-Average Shares Diluted	**104,964**	104,815	**104,838**	104,312
Weighted-Average Stock Awards and Shares Excluded from Diluted Earnings per Share due to the Anti-Dilutive Effect	**634**	220	**429**	752

6. COMMITMENTS AND CONTINGENCIES

Contingencies

The Company is a defendant in various legal proceedings arising in the normal course of its business. When deemed necessary, the Company establishes reserves for certain legal proceedings. All known liabilities are accrued based on an estimation process that includes the advice of legal counsel and subjective judgment of management. While the outcome and impact of such legal proceedings on the Company cannot be predicted with certainty, management believes that the resolution of these proceedings through settlement or adverse judgment will not have a material adverse effect on the Company s condensed consolidated financial position or cash flow. Operating results, however, could be significantly impacted in the reporting periods in which such matters are resolved.

While management believes established reserves are adequate, it is reasonably possible that the Company could incur approximately $1.0 million of additional loss with respect to those matters in which reserves have been established. Future changes in facts and circumstances could result in the actual liability exceeding the estimated ranges of loss and amounts accrued.

Environmental Matters

On November 4, 2009, the Company and the Pennsylvania Department of Environmental Protection (PaDEP) entered into a single settlement agreement (Consent Order) covering a number of separate, unrelated environmental issues occurring in 2008 and 2009, including releases of drilling mud and other substances, record keeping violations at various wells and alleged natural gas contamination of 13 water wells in Susquehanna County, Pennsylvania. The Company paid an aggregate $120,000 civil penalty with respect to all the matters covered by the Consent Order, which were consolidated at the request of the PaDEP.

On April 15, 2010, the Company and PaDEP reached agreement on modifications to the Consent Order (First Modified Consent Order). In the First Modified Consent Order, PaDEP and the Company agreed that the Company will provide a permanent source of potable water to 14 households, most of which the Company has already been supplying with water. The Company agreed to plug and abandon three vertical wells in close proximity to two of the households and to bring into compliance a fourth well in the nine square mile area of concern in Susquehanna County. The Company agreed to complete these actions prior to any new well drilling permits being issued for drilling in Pennsylvania, and prior to initiating hydraulic fracturing of seven wells already drilled in the area of concern. The Company also agreed to postpone drilling of new wells in the area of concern for one year. In addition, the Company agreed to take certain other actions if requested by PaDEP, which could include the plugging and abandonment of up to eleven additional wells. In the event the PaDEP requires the Company to plug and abandon all eleven additional wells in the area of concern, the decrease in production would have a minimal impact on the Company s overall production.

Under the First Modified Consent Order, the Company paid a $240,000 civil penalty and agreed to pay an additional $30,000 per month until all obligations under the First Modified Consent Order are satisfied, which is expected by November 2010. As of June 30, 2010, the Company has paid an additional $60,000 under the First Modified Consent Order. The Company is vigorously pursuing compliance with the First Modified Consent Order; however, there are no assurances that the PaDEP will not require additional actions.

On July 19, 2010, the Company and the PaDEP entered a Second Modification to Consent Order (Second Modified Consent Order) under which the Company and the PaDEP agreed that the Company has satisfactorily plugged and abandoned the three vertical wells and brought the fourth well into compliance. As a result, the Company and the PaDEP agreed that the PaDEP will commence the processing and issuance of new well drilling permits outside the area of concern so long as the Company continues to provide temporary potable water and offers to provide gas/water separators to the 14 households and within 60 days of the Second Modified Consent Order permanently restores or replaces the water supplies to the 14 households. No penalties were assessed under the Second Modified Consent Order.

CABOT OIL & GAS CORPORATION

NOTES TO THE CONDENSED CONSOLIDATED FINANCIAL STATEMENTS (Unaudited) (Continued)

As of June 30, 2010, the Company had paid $300,000 and had agreed to pay an additional $30,000 per month until all obligations under the Modified Consent Order are satisfied, which is expected by November 2010. The Company is vigorously pursuing compliance with the Modified Consent Order; however, there are no assurances that the PaDEP will not require additional actions.

Firm Gas Transportation Agreements

The Company has incurred, and will incur over the next several years, demand charges on firm gas transportation agreements. These agreements provide firm transportation capacity rights on pipeline systems primarily in the North region. The remaining terms on these agreements range from less than one year to approximately 17 years and require the Company to pay transportation demand charges regardless of the amount of pipeline capacity utilized by the Company. If the Company does not utilize the capacity, it can release it to others, thus reducing its potential liability. The agreements that the Company previously had in place on pipeline systems in Canada were transferred in April 2009 to the buyer in connection with the sale of the Company s Canadian properties (discussed in Note 2).

During the first six months of 2010, the Company entered into new firm gas transportation arrangements with third party pipelines to transport approximately 296 Mmcf/day in the North region. One of the new agreements commenced in the second quarter of 2010 and the remaining new agreements are expected to commence in the third and fourth quarters of 2011. These new agreements have terms of five to twelve years from the respective commencement dates. As of June 30, 2010, future obligations under firm gas transportation agreements, including the new agreements, were $247.6 million. As previously disclosed in the Form 10-K, obligations under firm gas transportation agreements in effect at December 31, 2009 were $80.4 million. For further information on these future obligations, please refer to Note 7 of the Notes to the Consolidated Financial Statements in the Form 10-K.

Drilling Rig Commitments

In the Form 10-K, the Company disclosed that it had total commitments during 2010 of $6.4 million on two drilling rigs in the South region that are under contracts with initial terms of greater than one year. One of these contracts ended in the second quarter of 2010 and the second will end in the third quarter of 2010. During the first half of 2010, the Company entered into commitments on two drilling rigs in the South region. As of June 30, 2010, the Company had outstanding commitments of $3.9 million on three drilling rigs in the South region. The Company does not have any commitments that extend beyond 2010.

7. DERIVATIVE INSTRUMENTS AND HEDGING ACTIVITIES

The Company periodically enters into commodity derivative instruments to hedge its exposure to price fluctuations on natural gas and crude oil production. The Company s credit agreement restricts the ability of the Company to enter into commodity hedges other than to hedge or mitigate risks to which the Company has actual or projected exposure or as permitted under the Company s risk management policies and not subjecting the Company to material speculative risks. All of the Company s derivatives are used for risk management purposes and are not held for trading purposes. As of June 30, 2010, the Company had 23 derivative contracts open: 15 natural gas price swap arrangements, six natural gas basis swaps and two crude oil price swap arrangements. During the first six months of 2010, the Company entered into five new derivative contracts covering anticipated crude oil production for 2010 and natural gas production for 2011. These natural gas basis swaps mitigate the risk associated with basis differentials that may expand or increase over time, thus reducing the exposure and risk of basis fluctuations.

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CABOT OIL & GAS CORPORATION

NOTES TO THE CONDENSED CONSOLIDATED FINANCIAL STATEMENTS (Unaudited) (Continued)

As of June 30, 2010, the Company had the following outstanding commodity derivatives:

Commodity and Derivative Type	Weighted-Average Contract Price		Volume		Contract Period
Derivatives designated as Hedging Instruments					
Natural Gas Swap	$ 9.30	per Mcf	17,977	Mmcf	July - December 2010
Natural Gas Swap	$ 6.26	per Mcf	12,909	Mmcf	January - December 2011
Crude Oil Swap	$ 104.25	per Bbl	366	Mbbl	July - December 2010
Derivatives not designated as Hedging Instruments					
Natural Gas Basis Swap	$ (0.27)	per Mcf	16,123	Mmcf	January - December 2012

The change in the fair value of derivatives designated as hedges that is effective is recorded to Accumulated Other Comprehensive Income in Stockholders Equity in the Balance Sheet. The ineffective portion of the change in the fair value of derivatives designated as hedges, and the change in fair value of derivatives not designated as hedges, are recorded currently in earnings as a component of Natural Gas Production and Crude Oil and Condensate Revenue, as appropriate.

The following schedules reflect the fair values of derivative instruments on the Company s condensed consolidated financial statements:

Effect of derivative instruments on the Condensed Consolidated Balance Sheet

(In thousands)	Balance Sheet Location	Fair Value Asset (Liability) June 30, 2010	Fair Value Asset (Liability) December 31, 2009
Derivatives designated as hedging instruments			
Natural Gas Commodity Contracts	Derivative Contracts - current assets	**$ 75,765**	$ 99,151
Natural Gas Commodity Contracts	Accrued Liabilities	**$**	$ (425)
Natural Gas Commodity Contracts	Derivative Contracts - long-term assets	**3,629**	
Crude Oil Commodity Contracts	Derivative Contracts - current assets	**10,008**	15,535
		$ 89,402	$ 114,261
Derivatives not designated as hedging instruments			
Natural Gas Commodity Contracts	Other Liabilities	**$ (1,599)**	$ (1,954)
		$ 87,803	$ 112,307

At June 30, 2010 and December 31, 2009, unrealized gains of $89.4 million ($55.4 million, net of tax) and $114.3 million ($71.9 million, net of tax), respectively, were recorded in Accumulated Other Comprehensive Income. Based upon estimates at June 30, 2010, the Company expects to reclassify $53.2 million in after-tax income associated with its commodity hedges from Accumulated Other Comprehensive Income to the Condensed Consolidated Statement of Operations over the next 12 months.

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CABOT OIL & GAS CORPORATION

NOTES TO THE CONDENSED CONSOLIDATED FINANCIAL STATEMENTS (Unaudited) (Continued)

Effect of derivative instruments on the Condensed Consolidated Statement of Operations

Derivatives designated as Hedging Instruments	Amount of Gain (Loss) Recognized in OCI on Derivative (Effective Portion)				Location of Gain (Loss) Reclassified from Accumulated OCI into Income	Amount of Gain (Loss) Reclassified from Accumulated OCI into Income (Effective Portion)			
	Three Months Ended June 30,		Six Months Ended June 30,			Three Months Ended June 30,		Six Months Ended June 30,	
(In thousands)	2010	2009	2010	2009		2010	2009	2010	2009
Natural Gas Commodity Contracts	**$ (6,266)**	$ (18,980)	**$ 50,938**	$ 141,694	Natural Gas Production Revenues	**$ 41,812**	$ 100,956	**$ 70,253**	$ 182,666
Crude Oil Contracts	**4,195**	18,236	**3,818**	(4,301)	Crude Oil and Condensate Revenues	**4,779**	5,972	**9,362**	13,356
	$ (2,071)	$ (744)	**$ 54,756**	$ 137,393		**$ 46,591**	$ 106,928	**$ 79,615**	$ 196,022

For the three and six months ended June 30, 2010 and 2009, respectively, there was no ineffectiveness recorded in our condensed consolidated statement of operations related to our derivative instruments.

Derivatives not qualifying as Hedging Instruments	Location of Gain (Loss) Recognized in Income on Derivative	Three Months Ended June 30,		Six Months Ended June 30,	
(In thousands)		2010	2009	2010	2009
Natural Gas Commodity Contracts	Natural Gas Production Revenues	**$ 942**	$ (126)	**$ 355**	$ 815

Additional Disclosures about Derivative Instruments and Hedging Activities

The use of derivative instruments involves the risk that the counterparties will be unable to meet their obligation under the agreement. The Company enters into derivative contracts with multiple counterparties in order to limit its exposure to individual counterparties. The Company also has netting arrangements with all of its counterparties that allow it to offset payables against receivables from separate derivative contracts with that counterparty.

The counterparties to the Company s derivative instruments are also lenders under its credit facility. The Company s credit facility and derivative instruments contain certain cross default and acceleration provisions that may require immediate payment of its derivative liability in certain situations.

8. FAIR VALUE MEASUREMENTS

Effective January 1, 2009, the Company applied the authoritative guidance that applies to non-financial assets and liabilities required to be measured and recorded at fair value. The Company previously adopted the guidance as it relates to financial assets and liabilities that are measured at fair value on a recurring basis effective January 1, 2008.

This guidance established a formal framework for measuring fair values of assets and liabilities in financial statements that are already required by generally accepted accounting principles (GAAP) to be measured at fair value. Fair value is the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date (exit price). The transaction is based on a hypothetical transaction in the principal or most advantageous market considered from the perspective of the market participant that holds the asset or owes the liability.

The Company utilizes market data or assumptions that market participants who are independent, knowledgeable and willing and able to transact would use in pricing the asset or liability, including assumptions about risk and the risks inherent in the inputs to the valuation technique. These inputs can be readily observable, market corroborated or generally unobservable. The Company attempts to utilize valuation techniques that maximize the use of observable inputs and minimize the use of unobservable inputs. The Company is able to classify fair value balances based on the observability of those inputs. A formal fair value hierarchy was established based on the inputs used to measure fair value. The hierarchy gives the highest priority to Level 1 measurements and the lowest priority to level 3 measurements, and accordingly, Level 1 measurements should be used whenever possible.

The Company has classified its assets and liabilities into these levels depending upon the data relied on to determine the fair values. For further information regarding the fair value hierarchy, refer to Note 11 of the Notes to the Consolidated Financial Statements in the Form 10-K.

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CABOT OIL & GAS CORPORATION

NOTES TO THE CONDENSED CONSOLIDATED FINANCIAL STATEMENTS (Unaudited) (Continued)

Non-Financial Assets and Liabilities

The Company discloses or recognizes its non-financial assets and liabilities, such as asset retirement obligations and impairments of long-lived assets, at fair value on a nonrecurring basis. During the three and six month periods ended June 30, 2010, the Company recorded an impairment related to certain oil and gas properties held for sale. Refer to Note 2 for additional disclosures related to fair value associated with the impaired properties. As none of the Company s other non-financial assets and liabilities were impaired as of June 30, 2010 and 2009 and no other fair value measurements were required to be recognized on a non-recurring basis, additional disclosures were not provided.

Financial Assets and Liabilities

Our financial assets and liabilities are measured at fair value on a recurring basis. The following fair value hierarchy table presents information about the Company s financial assets and liabilities measured at fair value on a recurring basis as of June 30, 2010:

(In thousands)	Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Balance as of June 30, 2010
Assets				
Rabbi Trust Deferred Compensation Plan	$ 13,441	$	$	**$ 13,441**
Derivative Contracts			89,402	**89,402**
Total Assets	$ 13,441	$	$ 89,402	**$ 102,843**
Liabilities				
Rabbi Trust Deferred Compensation Plan	$ 19,727	$	$	**$ 19,727**
Derivative Contracts			1,599	**1,599**
Total Liabilities	$ 19,727	$	$ 1,599	**$ 21,326**

The Company s investments associated with its Rabbi Trust Deferred Compensation Plan consist of mutual funds and deferred shares of the Company s common stock that are publicly traded and for which market prices are readily available.

The derivative contracts were measured based on quotes from the Company s counterparties. Such quotes have been derived using valuation models that consider various inputs including current market and contractual prices for the underlying instruments, quoted forward prices for natural gas and crude oil, volatility factors and interest rates, such as a LIBOR curve for a similar length of time as the derivative contract term as applicable. These estimates are verified using relevant NYMEX futures contracts or are compared to multiple quotes obtained from counterparties for reasonableness. The Company measured the nonperformance risk of its counterparties by reviewing credit default swap spreads for the various financial institutions in which it has derivative transactions. The resulting reduction to the net receivable derivative contract position was $0.2 million. In times where the Company has net derivative contract liabilities, the nonperformance risk of the Company is evaluated using a market credit spread provided by the Company s bank.

CABOT OIL & GAS CORPORATION

NOTES TO THE CONDENSED CONSOLIDATED FINANCIAL STATEMENTS (Unaudited) (Continued)

The following table sets forth a reconciliation of changes for the three and six month periods ended June 30, 2010 and 2009 in the fair value of financial assets and liabilities classified as Level 3 in the fair value hierarchy:

	Three Months Ended June 30,		Six Months Ended June 30,	
(In thousands)	**2010**	**2009**	**2010**	**2009**
Balance at beginning of period	**$ 135,532**	$ 405,186	**$ 112,307**	$ 355,202
Total Gains or (Losses) (Realized or Unrealized):				
Included in Earnings [(1)]	**47,534**	106,802	**79,972**	196,837
Included in Other Comprehensive Income	**(48,672)**	(107,672)	**(24,861)**	(58,629)
Purchases, Issuances and Settlements	**(46,591)**	(106,928)	**(79,615)**	(196,022)
Transfers In and/or Out of Level 3				
Balance at end of period	**$ 87,803**	$ 297,388	**$ 87,803**	$ 297,388

(1) *A gain of $0.9 million and $0.4 million for the three and six months ended June 30, 2010 and a loss of $0.1 million, respectively, and a gain of $0.8 million for the three and six months ended June 30, 2009, respectively, was unrealized and included in Natural Gas Production Revenues in the Statement of Operations.*

There were no transfers between Level 1 and Level 2 measurements for the three and six months ended June 30, 2010.

Fair Value of Other Financial Instruments

The estimated fair value of financial instruments is the amount at which the instrument could be exchanged currently between willing parties. The carrying amounts reported in the Condensed Consolidated Balance Sheet for cash and cash equivalents, accounts receivable and accounts payable approximate fair value due to the short-term maturities of these instruments.

The fair value of long-term debt is the estimated cost to acquire the debt, including a credit spread for the difference between the issue rate and the period end market rate. The credit spread is the Company s default or repayment risk. The credit spread (premium or discount) is determined by comparing the Company s fixed-rate notes and credit facility to new issuances (secured and unsecured) and secondary trades of similar size and credit statistics for both public and private debt. The fair value of all of the notes and credit facility is based on interest rates currently available to the Company.

The Company uses available market data and valuation methodologies to estimate the fair value of debt. The carrying amounts and fair values of long-term debt are as follows:

	June 30, 2010		December 31, 2009	
(In thousands)	**Carrying Amount**	**Estimated Fair Value**	**Carrying Amount**	**Estimated Fair Value**
Long-Term Debt	**$ 1,015,000**	**$ 1,134,677**	$ 805,000	$ 863,559

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CABOT OIL & GAS CORPORATION

NOTES TO THE CONDENSED CONSOLIDATED FINANCIAL STATEMENTS (Unaudited) (Continued)

9. COMPREHENSIVE INCOME / (LOSS)

Comprehensive Income / (Loss) includes Net Income and certain items recorded directly to Stockholders Equity and classified as Accumulated Other Comprehensive Income. The following tables illustrate the calculation of Comprehensive Income for the three and six months ended June 30, 2010 and 2009:

	Three Months Ended June 30,			
(In thousands)	**2010**		**2009**	
Net Income		**$ 21,682**		$ 25,502
Other Comprehensive Income / (Loss), net of taxes:				
Reclassification Adjustment for Settled Contracts, net of taxes of $17,219 and $40,182, respectively		**(29,372)**		(66,746)
Changes in Fair Value of Hedge Positions, net of taxes of $325 and $277, respectively		**(1,746)**		(467)
Defined Benefit Pension and Postretirement Plans:				
Amortization of Net Obligation at Transition, net of taxes of $(61) and $(59), respectively	**$ 97**		$ 99	
Amortization of Prior Service Cost, net of taxes of $(9) and $(67), respectively	**12**		112	
Amortization of Net Loss, net of taxes of $(257) and $(358), respectively	**396**	**505**	606	817
Foreign Currency Translation Adjustment, net of taxes of $41 and $(4,751), respectively		**(107)**		7,985
Total Other Comprehensive Income / (Loss)		**(30,720)**		(58,411)
Comprehensive Income / (Loss)		**$ (9,038)**		$ (32,909)

	Six Months Ended June 30,			
(In thousands)	**2010**		**2009**	
Net Income		**$ 50,378**		$ 73,082
Other Comprehensive Income / (Loss), net of taxes:				
Reclassification Adjustment for Settled Contracts, net of taxes of $29,537 and $73,413, respectively		**(50,078)**		(122,609)
Changes in Fair Value of Hedge Positions, net of taxes of $(21,122) and $(51,604), respectively		**33,634**		85,789
Defined Benefit Pension and Postretirement Plans:				
Amortization of Net Obligation at Transition, net of taxes of $(120) and $(118), respectively	**$ 196**		$ 198	
Amortization of Prior Service Cost, net of taxes of $(15) and $(134), respectively	**27**		225	
Amortization of Net Loss, net of taxes of $(570) and $(717), respectively	**928**	**1,151**	1,210	1,633
		120		7,034

Foreign Currency Translation Adjustment, net of taxes of $(41) and $(4,167), respectively		
Total Other Comprehensive Income / (Loss)	**(15,173)**	(28,153)
Comprehensive Income / (Loss)	**$ 35,205**	$ 44,929

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CABOT OIL & GAS CORPORATION

NOTES TO THE CONDENSED CONSOLIDATED FINANCIAL STATEMENTS (Unaudited) (Continued)

Changes in the components of Accumulated Other Comprehensive Income, net of taxes, for the six months ended June 30, 2010 were as follows:

Accumulated Other Comprehensive Income / (Loss), net of taxes (In thousands)	Net Gains / (Losses) on Cash Flow Hedges	Defined Benefit Pension and Postretirement Plans	Foreign Currency Translation Adjustment	Total
Balance at December 31, 2009	$ 71,872	$ (29,349)	$ (87)	$ 42,436
Net change in unrealized gain on cash flow hedges, net of taxes of $8,415	(16,444)			$ (16,444)
Net change in defined benefit pension and postretirement plans, net of taxes of $(705)		1,151		$ 1,151
Change in foreign currency translation adjustment, net of taxes of $(41)			120	$ 120
Balance at June 30, 2010	**$ 55,428**	**$ (28,198)**	**$ 33**	**$ 27,263**

10. PENSION AND OTHER POSTRETIREMENT BENEFITS

The components of net periodic benefit costs for the three and six months ended June 30, 2010 and 2009 were as follows:

(In thousands)	Three Months Ended June 30, 2010	2009	Six Months Ended June 30, 2010	2009
Qualified and Non-Qualified Pension Plans				
Current Period Service Cost	**$ 896**	$ 861	**$ 1,794**	$ 1,722
Interest Cost	**993**	928	**1,985**	1,856
Expected Return on Plan Assets	**(1,039)**	(671)	**(2,080)**	(1,342)
Amortization of Prior Service Cost	**21**	13	**42**	26
Amortization of Net Loss	**591**	794	**1,182**	1,588
Net Periodic Pension Cost	**$ 1,462**	$ 1,925	**$ 2,923**	$ 3,850
Postretirement Benefits Other than Pension Plans				
Current Period Service Cost	**$ 316**	$ 320	**$ 633**	$ 640
Interest Cost	**424**	398	**847**	797
Amortization of Prior Service Cost		167		333
Amortization of Net Loss	**62**	169	**316**	338
Amortization of Net Obligation at Transition	**158**	158	**316**	316
Total Postretirement Benefit Cost	**$ 960**	$ 1,212	**$ 2,112**	$ 2,424

Employer Contributions

The funding levels of the pension and postretirement plans are in compliance with standards set by applicable law or regulation. As of June 30, 2010, the Company contributed $5 million to its qualified pension plan. Additional contributions may be made prior to December 31, 2010. The Company does not have any required minimum funding obligations for its qualified pension plan in 2010. The Company previously disclosed in its financial statements for the year ended December 31, 2009 that it expected to contribute $0.5 million to its non-qualified pension plan and

$1.0 million to the postretirement benefit plan during 2010.

Subsequent Event

The Company is terminating its tax qualified defined benefit pension plan effective September 30, 2010, with the plan and its related trust to be liquidated following appropriate filings with the Pension Benefit Guaranty Corporation and Internal Revenue Service. Because no further benefits will be accrued under this pension plan after September 30, 2010, the Company s related supplemental nonqualified pension arrangements that provide benefits by reference to the tax qualified plan will effectively be frozen and no additional benefits will be accrued under those arrangements after September 30, 2010. Management has not yet completed its determination of the estimated curtailment gain or loss associated with the termination of the plans.

The Company also amended the Savings Investment Plan to provide for discretionary profit sharing contributions. The Company presently anticipates contributing to this plan an amount equal to 9% of an eligible plan participant s salary and bonus.

CABOT OIL & GAS CORPORATION

NOTES TO THE CONDENSED CONSOLIDATED FINANCIAL STATEMENTS (Unaudited) (Continued)

11. STOCK-BASED COMPENSATION

Compensation expense charged against income for stock-based awards (including the supplemental employee incentive plan) during the first half of June 30, 2010 and 2009 was $5.1 million and $11.3 million, respectively, and is included in General and Administrative Expense in the Condensed Consolidated Statement of Operations. Stock-based compensation expense in the second quarter of 2010 and 2009 was $1.9 million and $6.2 million, respectively.

As disclosed in the Form 10-K, the Company realized a $13.8 million tax benefit during the year ended December 31, 2009 related primarily to the federal tax deduction in excess of book compensation cost for employee stock-based compensation for 2008 and, to a lesser extent, state tax deductions for 2007. For regular federal income tax purposes, the Company was in a net operating loss position in 2008. In accordance with ASC 718, the Company recognized this tax benefit only to the extent it reduced the Company s income taxes payable. As the Company carried back net operating losses concurrent with its 2008 tax return filing, the income tax benefit related to stock-based compensation was recorded in Additional Paid-in Capital in 2009. Due to the Company s net operating loss carryforward position, no income tax benefit related to stock-based compensation has been recognized for 2010 or 2009. For further information regarding Stock-Based Compensation or the Company s Incentive Plans, please refer to Note 10 of the Notes to the Consolidated Financial Statements in the Form 10-K.

Restricted Stock Awards

During the first half of 2010, the Compensation Committee granted 11,800 restricted stock awards with a weighted-average grant date per share value of $38.88. The fair value of restricted stock grants is based on the average of the high and low stock price on the grant date. During the first half of 2010, 4,600 restricted stock awards granted in prior periods vested with a weighted-average grant date per share value of $30.10.

Compensation expense recorded for all unvested restricted stock awards for the six months ended June 30, 2010 and 2009 was $0.8 million and $0.2 million, respectively. The Company used an annual forfeiture rate ranging from 0% to 7.0% based on approximately ten years of the Company s history for this type of award to various employee groups.

Restricted Stock Units

During the six months ended June 30, 2010, 23,340 restricted stock units were granted to non-employee directors of the Company with a grant date per share value of $41.15. The fair value of these units is measured at the average of the high and low stock price on grant date and compensation expense is recorded immediately. These units immediately vest and are issued when the director ceases to be a director of the Company. The compensation cost, which reflects the total fair value of these units, recorded in the first half of 2010 and 2009 was $1.0 and $0.8 million, respectively. There was no expense recorded in the second quarter of either 2010 or 2009.

Stock Appreciation Rights

During the first half of 2010, the Compensation Committee granted 79,550 stock appreciation rights (SARs) to employees. These awards allow the employee to receive common stock of the Company equal to the intrinsic value over the $40.53 grant date market price that may result from the price appreciation during the contractual term of seven years. The Company calculates the fair value using a Black-Scholes model.

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CABOT OIL & GAS CORPORATION

NOTES TO THE CONDENSED CONSOLIDATED FINANCIAL STATEMENTS (Unaudited) (Continued)

The assumptions used in the Black-Scholes fair value calculation on the date of grant for SARs are as follows:

Weighted-Average Value per Stock Appreciation Rights Granted During the Period	**$ 18.96**
Assumptions	
Stock Price Volatility	**52.9%**
Risk Free Rate of Return	**2.4%**
Expected Dividend Yield	**0.3%**
Expected Term (in years)	**5.0**

Compensation expense recorded during the first half of 2010 and 2009 for SARs was $0.9 million and $1.3 million, respectively. Included in these amounts were $0.3 million and $0.7 million in the first half of 2010 and 2009, respectively, related to the immediate expensing of shares granted in 2010 and 2009 to retirement-eligible employees. Compensation expense in the second quarter of 2010 and 2009 was $0.4 million and $0.3 million, respectively.

Performance Share Awards

During 2010, the Compensation Committee granted three types of performance share awards to employees for a total of 347,170 performance shares. The performance period for two of the three types of these awards commenced on January 1, 2010 and ends December 31, 2012.

Awards totaling 84,470 performance shares are earned, or not earned, based on the comparative performance of the Company s common stock measured against sixteen other companies in the Company s peer group over a three year performance period. Depending on the Company s performance, employees may receive an aggregate of up to 100% of the fair market value of a share of common stock payable in common stock plus up to 100% of the fair market value of a share of common stock payable in cash.

Awards totaling 180,180 performance shares are earned, or not earned, based on the Company s internal performance metrics rather than performance compared to a peer group. The grant date per share value of this award was $40.53. These awards represent the right to receive up to 100% of the award in shares of common stock. The actual number of shares issued at the end of the performance period will be determined based on the Company s performance against three performance criteria set by the Company s Compensation Committee. An employee will earn one-third of the award granted for each internal performance metric that the Company meets at the end of the performance period. These performance criteria measure the Company s average production, average finding costs and average reserve replacement over three years. Based on the Company s probability assessment at June 30, 2010, it is considered probable that these three criteria will be met.

The third type of performance share award, totaling 82,520 performance shares, with a grant date per share value of $40.53, has a three-year graded performance period, one-third of the shares are issued on each anniversary date following the date of grant, provided that the Company has $100 million or more of operating cash flow for the year preceding the performance period. If the Company does not have $100 million or more of operating cash flow for the year preceding a performance period, then the portion of the performance shares that would have been issued on that date will be forfeited. As of June 30, 2010, it is considered probable that this performance metric will be met.

For all performance share awards granted to employees in 2010, an annual forfeiture rate ranging from 0% to 7% has been assumed based on the Company s history for this type of award to various employee groups.

For awards that are based on the internal metrics of the Company (performance condition), fair value is measured based on the average of the high and low stock price of the Company on the grant date and expense is amortized over the three year period. To determine the fair value for awards that are based on the Company s comparative performance against a peer group (market condition), the equity and liability components are bifurcated. On the

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CABOT OIL & GAS CORPORATION

NOTES TO THE CONDENSED CONSOLIDATED FINANCIAL STATEMENTS (Unaudited) (Continued)

grant date, the equity component was valued using a Monte Carlo binomial model and is amortized on a straight-line basis over three years. The liability component is valued at each reporting period by using a Monte Carlo binomial model.

The four primary inputs for the Monte Carlo model are the risk-free rate, volatility of returns, correlation in movement of total shareholder return and the expected dividend. An interpolated risk-free rate was generated from the Federal Reserve website for constant maturity treasuries for two and three year bonds (as of the reporting date) set equal to the remaining duration of the performance period. Volatility was set equal to the annualized daily volatility for the remaining duration of the performance period ending on the reporting date. Correlation in movement of total shareholder return was determined based on a correlation matrix that was created which identifies total shareholder return correlations for each pair of companies in the peer group, including the Company. The paired returns in the correlation matrix ranged from approximately 59% to approximately 84% for the Company and its peer group. The expected dividend is calculated using the total Company annual dividends expected to be paid ($0.12 per share) divided by the June 30, 2010 closing price of the Company s stock ($31.32 per share). Based on these inputs discussed above, a ranking was projected identifying the Company s rank relative to the peer group for each award period.

The following assumptions were used for the Monte Carlo model to value the liability components of the peer group measured performance share awards. The equity portion of the awards was valued on the respective grant date using the Monte Carlo model and this portion was not marked to market.

	Grant Date	June 30, 2010
Value per Share	$17.63 - $41.53	$3.91 - $8.34
Risk Free Rate of Return	1.33% - 1.74%	0.22% - 0.81%
Stock Price Volatility	37.65% - 61.76%	53.76% - 67.44%
Expected Dividend Yield	0.24% - 0.54%	0.38%

The Monte Carlo value per share for the liability component for all outstanding market condition performance share awards ranged from $3.91 to $8.34 at June 30, 2010. The long-term liability for market condition performance share awards, included in Other Liabilities in the Condensed Consolidated Balance Sheet, at June 30, 2010 and December 31, 2009 was $0.5 million and $1.1 million, respectively. The short-term liability, included in Accrued Liabilities in the Condensed Consolidated Balance Sheet, at June 30, 2010 and December 31, 2009, for market condition performance share awards was $0.3 million and $2.4 million, respectively.

During the first half of 2010, 363,284 performance shares were issued. As discussed in Note 10 of the Notes to the Consolidated Financial Statements in the Form 10-K, the performance period ended on December 31, 2009 for two types of performance awards granted in 2007. A total of 92,400 shares measured based on the Company s performance against a peer group (valued at $2.8 million) were issued in addition to cash of $1.3 million. A total of 150,100 shares measured based on internal performance metrics of the Company (valued at $5.3 million) were also issued. During the first quarter of 2010, 120,784 shares were issued (valued at $3.8 million), which represents one-third of the three-year graded performance share awards granted in 2009, 2008 and 2007 with a grant date per share value of $22.63, $48.48 and $35.22, respectively. These awards met the performance criteria that the Company had $100 million or more of operating cash flow for the awards granted in 2009 and positive operating income for awards granted in 2008 and 2007.

As of June 30, 2010, 225,800 shares of the Company s common stock representing issued stock in association with past performance share awards were deferred into the Rabbi Trust Deferred Compensation Plan. For the first half of 2010, an increase to the rabbi trust deferred compensation liability of $0.6 million was recognized. The net increase was due to an increase in the value of the investments held by the trust, partially offset by a decrease in the closing price of shares of the Company s common stock held by the trust from December 31, 2009 to June 30, 2010. This decrease in stock-based compensation expense was included in General and Administrative expense in the Condensed Consolidated Statement of Operations.

Total compensation cost recognized for both the equity and liability components of all performance share awards as well as expense related to the shares deferred into the rabbi trust during the six months ended June 30, 2010 and 2009 was $3.0 million and $8.8 million, respectively. Total compensation cost recognized for both the equity and liability components of all performance share awards as well as expense related to the shares deferred into the rabbi trust during the second quarter of 2010 and 2009 was $1.7 million and $5.7 million, respectively.

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Report of Independent Registered Public Accounting Firm

To the Board of Directors and Stockholders of

Cabot Oil & Gas Corporation:

We have reviewed the accompanying condensed consolidated balance sheet of Cabot Oil & Gas Corporation and its subsidiaries (the Company) as of June 30, 2010, and the related condensed consolidated statements of operations for the three-month and six-month periods ended June 30, 2010 and 2009 and the condensed consolidated statement of cash flows for the six-month periods ended June 30, 2010 and 2009. These interim financial statements are the responsibility of the Company s management.

We conducted our review in accordance with the standards of the Public Company Accounting Oversight Board (United States). A review of interim financial information consists principally of applying analytical procedures and making inquiries of persons responsible for financial and accounting matters. It is substantially less in scope than an audit conducted in accordance with the standards of the Public Company Accounting Oversight Board (United States), the objective of which is the expression of an opinion regarding the financial statements taken as a whole. Accordingly, we do not express such an opinion.

Based on our review, we are not aware of any material modifications that should be made to the accompanying condensed consolidated interim financial statements for them to be in conformity with accounting principles generally accepted in the United States of America.

We previously audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the consolidated balance sheet as of December 31, 2009, and the related consolidated statements of operations, of cash flows, of stockholders equity and of comprehensive income for the year then ended (not presented herein), and in our report dated February 26, 2010, which included an explanatory paragraph related to changes in the manner of accounting for fair value measurements, we expressed an unqualified opinion on those consolidated financial statements. In our opinion, the information set forth in the accompanying condensed consolidated balance sheet information as of December 31, 2009, is fairly stated in all material respects in relation to the consolidated balance sheet from which it has been derived.

/s/ PricewaterhouseCoopers LLP

Houston, Texas

July 30, 2010

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ITEM 2. Management s Discussion and Analysis of Financial Condition and Results of Operations

The following review of operations for the three and six month periods ended June 30, 2010 and 2009 should be read in conjunction with our Condensed Consolidated Financial Statements and the Notes included in this Form 10-Q and with the Consolidated Financial Statements, Notes and Management s Discussion and Analysis included in the Cabot Oil & Gas Annual Report on Form 10-K for the year ended December 31, 2009 (Form 10-K).

In 2009, we restructured our operations by combining the Rocky Mountain and Appalachian areas to form the North region and by combining the Anadarko Basin with its Texas and Louisiana areas to form the South region. Certain prior year amounts have been reclassified to reflect this reorganization. Additionally, we exited Canada through the sale of our reserves. Prior to the third quarter of 2009, we presented the geographic areas as East, Gulf Coast, West and Canada.

Overview

On an equivalent basis, our production for the six months ended June 30, 2010 increased by 12% compared to the six months ended June 30, 2009. For the six months ended June 30, 2010, we produced 57.1 Bcfe compared to production of 51.2 Bcfe for the six months ended June 30, 2009. Natural gas production was 54.4 Bcf and oil production was 424 Mbbls for the first half of 2010. Natural gas production increased by 11% when compared to the first half of 2009, which had production of 48.8 Bcf. This increase was primarily a result of increased production in the North region associated with the drilling program and the start up of our Lathrop compressor station in Susquehanna County, Pennsylvania. Partially offsetting the production increase in the North region were decreases in production in Canada due to the sale of our Canadian properties in April 2009, as well as lower production in the South region due to normal production declines, delays in completion, and a shift from gas to oil projects. Oil production increased by 11%, to 424 Mbbls from 383 Mbbls in the first half of 2009. This was primarily the result of increased production in the South region.

Our average realized natural gas price for the first half of 2010 was $5.99 per Mcf, 19% lower than the $7.38 per Mcf price realized in the first half of 2009. Our average realized crude oil price for the first half of 2010 was $97.04 per Bbl, 22% higher than the $79.55 per Bbl price realized in the first half of 2009. These realized prices include realized gains and losses resulting from commodity derivatives. For information about the impact of these derivatives on realized prices, refer to Results of Operations below. Commodity prices are determined by many factors that are outside of our control. Historically, commodity prices have been volatile, and we expect them to remain volatile. Commodity prices are affected by changes in market supply and demand, which are impacted by overall economic activity, weather, pipeline capacity constraints, inventory storage levels, basis differentials and other factors. As a result, we cannot accurately predict future natural gas, NGL and crude oil prices and, therefore, we cannot determine with any degree of certainty what effect increases or decreases will have on our future revenues, capital program or production volumes.

Operating revenues for the six months ended June 30, 2010 decreased by $30.7 million, or 7%, from the six months ended June 30, 2009 as the lower realized natural gas prices noted above more than offset the higher equivalent production. Natural gas production revenues decreased by $34.9 million, or 10 %, for the six months ended June 30, 2010 as compared to the six months ended June 30, 2009 due to the decrease in realized natural gas prices, partially offset by the increase in natural gas production. Crude oil and condensate revenues increased by $10.7 million, or 35%, for the first six months of 2010 as compared to the first six months of 2009, due to increases in realized crude oil prices and crude oil production. Brokered natural gas revenues decreased by $6.8 million, or 15%, due to a decreased sales price, partially offset by increased brokered volumes.

In addition to production volumes and commodity prices, finding and developing sufficient amounts of crude oil and natural gas reserves at economical costs are critical to our long-term success. For 2010, we expect to spend approximately $725 million in capital and exploration expenditures. We believe our cash on hand, operating cash flow in 2010 and borrowings from our credit facility will be sufficient to fund our budgeted capital and exploration spending. We will continue to assess the natural gas and crude oil price environment and our liquidity position and may increase or decrease our capital and exploration expenditures accordingly. For the six months ended June 30, 2010, we invested approximately $394 million in our exploration and development efforts.

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During the first six months of 2010, we drilled 45 gross wells (41 development, two exploratory and two extension wells) with a success rate of 98% compared to 82 gross wells (77 development, two exploratory and three extension wells) with a success rate of 98% for the comparable period of the prior year. For the full year of 2010, we plan to drill approximately 137 gross (107 net) wells.

We continue to remain focused on our strategies of pursuing lower risk drilling opportunities that provide more predictable results on our accumulated acreage position. Additionally, we intend to maintain spending discipline and manage our balance sheet in an effort to ensure sufficient liquidity, including cash resources and available credit. We believe these strategies are appropriate for our portfolio of projects and the current industry environment and will continue to add shareholder value over the long-term.

In June 2010, we sold our Woodford shale prospect located in Oklahoma to Continental Resources Inc. We received approximately $15.9 million in cash proceeds and recognized a $10.3 million gain on sale of assets. As a result of our decision to divest of certain oil and gas properties, we recognized an impairment loss of approximately $5.8 million related to the assets held for sale in the second quarter of 2010. In April 2009, we sold our Canadian properties to a privately held Canadian company for a $10.5 million loss. In the first quarter of 2009, we received approximately of $11.4 million in cash proceeds and recognized a $12.7 million gain on sale of assets primarily related to the sale of the Thornwood properties in the North region. Refer to Note 2 of the Notes to the Condensed Consolidated Financial Statements for further details.

In April 2009, we entered into a new revolving credit facility and terminated our prior credit facility. In June 2010, we amended the agreements governing our senior notes and credit facility to amend the required asset coverage ratio (the present value of our proved reserves plus working capital to debt) contained in the agreements. The amendment also impacted the ratio for maximum calculated indebtedness to borrowing base (as defined in the credit facility agreement). Refer to Note 4 of the Notes to the Condensed Consolidated Financial Statements for further details.

The preceding paragraphs, discussing our strategic pursuits and goals, contain forward-looking information. Please read Forward-Looking Information for further details.

Financial Condition

Capital Resources and Liquidity

Our primary sources of cash for the six months ended June 30, 2010 were funds generated from the sale of natural gas and crude oil production, realized derivative contracts, borrowings under our credit facility and asset dispositions. These cash flows were primarily used to fund our development and exploratory expenditures, in addition to payment of dividends. See below for additional discussion and analysis of cash flow.

We generate cash from the sale of natural gas and crude oil. Operating cash flow fluctuations are substantially driven by commodity prices and changes in our production volumes. Prices for crude oil and natural gas have historically been volatile, including seasonal influences characterized by peak demand and higher prices in the winter heating season; however, the impact of other risks and uncertainties, as described in our Form 10-K and other filings with the Securities and Exchange Commission, have also influenced prices throughout the recent years. Commodity prices continue to experience increased volatility due to adverse market conditions in the economy. In addition, fluctuations in cash flow may result in an increase or decrease in our capital and exploration expenditures. See Results of Operations for a review of the impact of prices and volumes on sales.

Our working capital is also substantially influenced by variables discussed above. From time to time, our working capital will reflect a surplus, while at other times it will reflect a deficit. This fluctuation is not unusual. We believe we have adequate credit availability and liquidity to meet our working capital requirements.

	Six Months Ended June 30,	
(In thousands)	**2010**	**2009**
Cash Flows Provided by Operating Activities	**$ 243,178**	$ 300,385
Cash Flows Used in Investing Activities	**(437,401)**	(230,166)
Cash Flows Provided by / (Used in) Financing Activities	**201,750**	(68,472)
Net Increase in Cash and Cash Equivalents	**$ 7,527**	$ 1,747

Operating Activities. Key components impacting net operating cash flows are commodity prices, production volumes and operating costs. Net cash provided by operating activities in the first six months of 2010 decreased by $57.2 million over the first six months of 2009. This decrease was mainly due to lower natural gas prices offset by higher crude oil prices and equivalent production. Average realized natural gas prices decreased by 19% for the first six months of 2010 compared to the first six months of 2009, while average realized crude oil prices increased by 22% compared to the same period. Equivalent production volumes increased by 12% for the six months ended June 30, 2010 compared to the six months ended June 30, 2009 as a result of higher natural gas and crude oil production. See Results of Operations for additional information relative to commodity price and production movements. We are unable to predict future commodity prices and, as a result, cannot provide any assurance about future levels of net cash provided by operating activities. Realized prices may decline in future periods.

As of June 30, 2010, we have natural gas price swaps covering 18.0 Bcf of our 2010 natural gas production at an average price of $9.30 per Mcf and natural gas price swaps covering 12.9 Bcf of our 2011 natural gas production at an average price of $6.26 per Mcf. Accordingly, based on our current hedge position, we are more subject to the effects of natural gas price volatility in 2010 than we were in 2009.

Investing Activities. The primary uses of cash in investing activities were capital spending. We established the budget for these amounts based on our current estimate of future commodity prices and cash flows. Due to the volatility of commodity prices and new opportunities which may arise, our capital expenditures may be periodically adjusted during any given year. Cash flows used in investing activities increased by $207.3 million from the first six months of 2010 compared to the first six months of 2009. The increase primarily was due to an increase of $144.3 million in capital expenditures offset by lower proceeds from sale of assets of $62.9 million.

Financing Activities. Cash flows provided by financing activities increased by $270.2 million from the first six months of 2009 to the first six months of 2010. This was primarily due to an increase in borrowings under our credit facility in the first six months of 2010 and to debt repayments in the first six months of 2009.

At June 30, 2010, we had $353.0 million of borrowings outstanding under our unsecured credit facility at a weighted-average interest rate of 3.75%. The credit facility provides for an available credit line of $500 million and contains an accordion feature allowing us to increase the available credit line to $600 million, if any one or more of the existing banks or new banks agree to provide such increased commitment amount. The available credit line is subject to adjustment on the basis of the present value of estimated future net cash flows from proved oil and gas reserves (as determined by the banks based on our reserve reports and engineering reports) and certain other assets and the outstanding principal balance of our senior notes. As of June 30, 2010, our available credit under our credit facility is $146.0 million.

In June 2010, the Company amended the agreements governing its senior notes and credit facility to amend the required asset coverage ratio (the present value of the Company s proved reserves plus working capital to debt) contained in the agreements. The amendments revised the calculation of present value of proved reserves to reflect specified pricing assumptions based on quoted futures prices in lieu of historical realized prices, reduced the limit on proved undeveloped reserves included in the calculation from 35% to 30%, and increased the required ratio from 1.75:1 from 1.50:1. The amendments to the senior note agreements also provided that for so long as a borrowing base calculation is required under the Company s credit facility, the Company s debt may not exceed 115% of such borrowing base. If such a borrowing base calculation is not required under the credit facility, the Company would no longer be subject to the asset coverage ratio under the agreements, but would instead be required to maintain a ratio of debt to consolidated EBITDAX (as defined) not to exceed 3.0:1.

We strive to manage our debt at a level below the available credit line in order to maintain excess borrowing capacity. Our revolving credit facility includes a covenant limiting our total debt. Management believes that, with internally generated cash, existing cash and availability under our revolving credit facility, we have the capacity to finance our spending plans and maintain our strong financial position. At the same time, we continue to closely monitor the capital markets.

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Capitalization

Information about our capitalization is as follows:

(Dollars in millions)	June 30, 2010	December 31, 2009
Debt [1]	**$ 1,015.0**	$ 805.0
Stockholders Equity	**1,845.9**	1,812.5
Total Capitalization	**$ 2,860.9**	$ 2,617.5
Debt to Capitalization	**35.5%**	30.8%
Cash and Cash Equivalents	**$ 47.7**	$ 40.2

(1) *Includes $353.0 million and $143.0 million of borrowings outstanding under our revolving credit facility at June 30, 2010 and December 31, 2009, respectively.*

During the six months ended June 30, 2010, we paid dividends of $6.2 million ($0.06 per share) on our common stock. A regular dividend has been declared for each quarter since we became a public company in 1990.

Capital and Exploration Expenditures

On an annual basis, we generally fund most of our capital and exploration activities, excluding any significant oil and gas property acquisitions, with cash generated from operations and, when necessary, our revolving credit facility. We budget these capital expenditures based on our projected cash flows for the year.

The following table presents major components of capital and exploration expenditures for the six-month period ended June 30, 2010 and 2009:

(In millions)	Six Months Ended June 30, 2010	2009
Capital Expenditures		
Drilling and Facilities [1]	**$ 261.6**	$ 222.8
Leasehold Acquisitions	**90.3**	11.5
Acquisitions	**0.8**	0.2
Pipeline and Gathering	**18.1**	7.9
Other	**4.5**	1.3
	375.3	243.7
Exploration Expense	**18.7**	16.9
Total	**$ 394.0**	$ 260.6

(1) *Includes Canadian currency translation effects of $4.6 million in 2009. There was no impact from Canadian currency translation in 2010.*

For the full year of 2010, we plan to drill approximately 137 gross (107 net) wells. This 2010 drilling program includes approximately $725 million in total capital and exploration expenditures. See the Overview discussion for additional information regarding the current year drilling program. We will continue to assess the natural gas and crude oil price environment and our liquidity position and may increase or decrease the capital and exploration expenditures accordingly.

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Contractual Obligations

At June 30, 2010, we were obligated to make future payments under drilling rig commitments and firm gas transportation agreements. For further information, please refer to Firm Gas Transportation Agreements and Drilling Rig Commitments under Note 6 in the Notes to the Condensed Consolidated Financial Statements and Note 7 in the Notes to Consolidated Financial Statements included in our Form 10-K.

Critical Accounting Policies and Estimates

Our discussion and analysis of our financial condition and results of operations are based upon condensed consolidated financial statements, which have been prepared in accordance with accounting principles generally accepted and adopted in the United States. The preparation of these financial statements requires us to make estimates and judgments that affect the reported amounts of assets, liabilities, revenues and expenses. See our Form 10-K for further discussion of our critical accounting policies.

Recently Adopted Accounting Standards

In February 2010, the Financial Accounting Standards Board (FASB) issued Accounting Standards Update (ASU) No. 2010-09, Subsequent Events, which amends Accounting Standards Codification (ASC) 855 to eliminate the requirement to disclose the date through which management has evaluated subsequent events in the financial statements. ASU No. 2010-09 was effective upon issuance and its adoption had no impact on our financial position, results of operations or cash flows.

Effective January 1, 2010, we partially adopted the provisions of FASB ASU No. 2010-06, Improving Disclosures about Fair Value Measurements, which amends ASC 820-10-50 to require new disclosures concerning (1) transfers into and out of Levels 1 and 2 of the fair value measurement hierarchy, and (2) activity in Level 3 measurements. In addition, ASU No. 2010-06 clarifies certain existing disclosure requirements regarding the level of disaggregation and inputs and valuation techniques and makes conforming amendments to the guidance on employers disclosures about postretirement benefit plans assets. The requirements to disclose separately purchases, sales, issuances, and settlements in the Level 3 reconciliation are effective for fiscal years beginning after December 15, 2010 (and for interim periods within such years). The principal impact was to require the expansion of our disclosure regarding our derivative instruments. Accordingly, we will apply the disclosure requirements relative to the Level 3 reconciliation in the first quarter of 2011. There was no impact on our financial position, results of operations or cash flows as a result of the partial adoption of ASU No. 2010-06. For further information, please refer to Note 8 in the Notes to the Condensed Consolidated Financial Statements.

Results of Operations

Second Quarters of 2010 and 2009 Compared

We reported net income in the second quarter of 2010 of $21.7 million, or $0.21 per share. For the second quarter of 2009, we reported net income of $25.5 million, or $0.25 per share. Net income decreased in the second quarter of 2010 by $3.8 million, primarily due to a decrease in operating revenues and an increase in operating expenses offset by an increase in gain / (loss) on sale of assets. Operating revenues decreased by $9.4 million primarily due to a reduction in natural gas production revenues partially offset by increases in crude oil condensate revenues, brokered natural gas revenues and other revenues. Operating expenses increased by $13.8 million between periods due primarily to increases in depreciation, depletion and amortization, impairment of unproved properties, partially offset by decreased general and administrative expenses, including stock-based compensation.

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Natural Gas Production Revenues

Our average total company realized natural gas production sales price, including the realized impact of derivative instruments, was $5.48 per Mcf for the three months ended June 30, 2010 compared to $7.25 per Mcf for the comparable period of the prior year. These prices include the realized impact of derivative instrument settlements, which increased the price by $1.44 per Mcf in 2010 and by $4.15 per Mcf in 2009. The following table excludes the unrealized gain from the change in fair value of our derivatives that do not qualify for hedging of $0.9 million for the quarter ended June 30, 2010 and the unrealized loss from the change in derivative fair value of $0.1 million for the quarter ended June 30, 2009, which have been included within Natural Gas Production Revenues in the Condensed Consolidated Statement of Operations.

	Three Months Ended June 30,		Variance	
	2010	**2009**	**Amount**	**Percent**
Natural Gas Production *(Mmcf)*				
North	**17,124**	11,843	5,281	45%
South	**11,837**	12,134	(297)	(2%)
Canada		353	(353)	(100%)
Total Company	**28,961**	24,330	4,631	19%
Natural Gas Production Sales Price *($/Mcf)*				
North	**$ 4.47**	$ 6.29	$ (1.82)	(29%)
South	**$ 6.95**	$ 8.30	$ (1.35)	(16%)
Canada	**$**	$ 3.22	$ (3.22)	(100%)
Total Company	**$ 5.48**	$ 7.25	$ (1.77)	(24%)
Natural Gas Production Revenue *(In thousands)*				
North	**$ 76,503**	$ 74,440	$ 2,063	3%
South	**82,316**	100,761	(18,445)	(18%)
Canada		1,138	(1,138)	(100%)
Total Company	**$ 158,819**	$ 176,339	$ (17,520)	(10%)
Price Variance Impact on Natural Gas Production Revenue *(In thousands)*				
North	**$ (30,960)**			
South	**(16,098)**			
Canada				
Total Company	**$ (47,058)**			
Volume Variance Impact on Natural Gas Production Revenue *(In thousands)*				
North	**$ 33,023**			
South	**(2,347)**			
Canada	**(1,138)**			
Total Company	**$ 29,538**			

The decrease in Natural Gas Production Revenue of $17.5 million, excluding the impact of the unrealized gain discussed above, is due to the decrease in realized natural gas prices in both the North and South regions, decreased production in the South region associated with normal production declines, delays in completions and a shift from gas to oil projects, as well as the sale of our Canadian properties in April 2009. Partially offsetting these decreases was an increase in natural gas production in the North region associated with increased drilling and the start up of the Lathrop compressor station in the Marcellus shale.

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Brokered Natural Gas Revenue and Cost

	Three Months Ended June 30, 2010	Three Months Ended June 30, 2009	Variance Amount	Variance Percent
Sales Price *($/Mcf)*	**$ 5.04**	$ 4.83	$ 0.21	4%
Volume Brokered *(Mmcf)*	**x 2,649**	x 2,424	225	9%
Brokered Natural Gas Revenues *(In thousands)*	**$ 13,348**	$ 11,704		
Purchase Price *($/Mcf)*	**$ 4.45**	$ 4.41	$ 0.04	1%
Volume Brokered *(Mmcf)*	**x 2,649**	x 2,424	225	9%
Brokered Natural Gas Cost *(In thousands)*	**$ 11,793**	$ 10,684		
Brokered Natural Gas Margin *(In thousands)*	**$ 1,555**	$ 1,020	$ 535	52%

(In thousands)	
Sales Price Variance Impact on Revenue	**$ 556**
Volume Variance Impact on Revenue	**1,087**
	$ 1,643

(In thousands)	
Purchase Price Variance Impact on Purchases	**$ (116)**
Volume Variance Impact on Purchases	**(992)**
	$ (1,108)

The increased brokered natural gas margin is a result of an increase in brokered volumes coupled with an increase in sales price that outpaced the increase in purchase price.

Crude Oil and Condensate Revenues

Our average total company realized crude oil sales price, including the realized impact of derivative instruments, was $96.70 per Bbl for the second quarter of 2010 compared to $83.76 per Bbl for the second quarter of 2009. These prices include the realized impact of derivative instrument settlements, which increased the price by $21.82 per Bbl in 2010 and by $30.78 per Bbl in 2009. There was no revenue impact from the unrealized change in crude oil and condensate derivative fair value for the three months ended June 30, 2010 and 2009.

	Three Months Ended June 30,		Variance	
	2010	**2009**	**Amount**	**Percent**
Crude Oil Production *(Mbbl)*				
North	**26**	30	(4)	(13%)
South	**193**	162	31	19%
Canada		2	(2)	(100%)
Total Company	**219**	194	25	13%
Crude Oil Sales Price *($/Bbl)*				
North	**$ 67.27**	$ 52.61	$ 14.66	28%
South	**$ 100.65**	$ 90.15	$ 10.50	12%
Canada	**$**	$ 45.14	$ (45.14)	(100%)
Total Company	**$ 96.70**	$ 83.76	$ 12.94	15%
Crude Oil Revenue *(In thousands)*				
North	**$ 1,744**	$ 1,602	$ 142	9%
South	**19,467**	14,514	4,953	34%
Canada		94	(94)	(100%)
Total Company	**$ 21,211**	$ 16,210	$ 5,001	31%
Price Variance Impact on Crude Oil Revenue *(In thousands)*				
North	**$ 328**			
South	**2,030**			
Canada				
Total Company	**$ 2,358**			
Volume Variance Impact on Crude Oil Revenue *(In thousands)*				
North	**$ (186)**			
South	**2,923**			
Canada	**(94)**			
Total Company	**$ 2,643**			

The $5.0 million increase in crude oil and condensate revenues is primarily due to an increase in realized crude oil prices in the North and South regions and an increase in crude oil production in the South region due to a shift from gas to oil projects. These increases are partially offset by lower production in the North region and Canada.

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Impact of Derivative Instruments on Operating Revenues

The following table reflects the realized impact of cash settlements and the net unrealized change in fair value of derivative instruments:

	Three Months Ended June 30,			
	2010		2009	
(In thousands)	Realized	Unrealized	Realized	Unrealized
Operating Revenues Increase / (Decrease) to Revenue				
Cash Flow Hedges				
Natural Gas Production	**$ 41,812**	**$**	$ 100,956	$
Crude Oil	**4,779**		5,972	
Total Cash Flow Hedges	**46,591**	**$**	106,928	
Other Derivative Financial Instruments				
Natural Gas Basis Swaps		**942**		(126)
Total Other Derivative Financial Instruments		**942**		(126)
Total Cash Flow Hedges and Other Derivative Financial Instruments	**$ 46,591**	**$ 942**	$ 106,928	$ (126)

We are exposed to market risk on derivative instruments to the extent of changes in market prices of natural gas and crude oil. However, the market risk exposure on these derivative contracts is generally offset by the gain or loss recognized upon the ultimate sale of the commodity. Although notional contract amounts are used to express the volume of natural gas price agreements, the amounts that can be subject to credit risk in the event of non-performance by third parties are substantially smaller. We do not anticipate any material impact on our financial results due to non-performance by third parties. Our primary derivative contract counterparties are Bank of Montreal, BNP Paribas, JPMorgan Chase, Key Bank, Bank of America and Morgan Stanley.

Operating Expenses

Total costs and expenses from operations increased by $13.8 million in the second quarter of 2010 compared to the same period of 2009. The primary reasons for this fluctuation are as follows:

Depreciation, Depletion and Amortization increased by $12.6 million from the second quarter of 2009 compared to the second quarter of 2010. This is primarily due to a higher DD&A rate as a result of higher capital costs and increased equivalent production volumes.

Impairment of Unproved Properties increased $2.3 million primarily due to increased unproved leasehold costs in Susquehanna County and South Texas in late 2009 and early 2010.

General and Administrative expenses decreased by $4.3 million from the second quarter of 2009 compared to the second quarter of 2010. This decrease is primarily due to lower stock compensation and pension and post retirement benefit expense, partially offset by increased salaries and wages, incentive compensation and professional service costs.

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Gain on Sale of Assets

An aggregate gain of $4.4 million was recognized in the second quarter of 2010. During the second quarter of 2010, a gain of $10.3 million was recognized on the sale of the Woodford shale prospect, offset by an impairment charge of $5.8 million on assets held for sale. In the second quarter of 2009, a loss of $16.6 million was recognized primarily due to the sale of the our Canadian properties.

Income Tax Expense

Income tax expense increased by $0.9 million in the second quarter of 2010 due to a higher effective tax rate partially offset by lower pre-tax income compared to the second quarter of 2009. The effective tax rates for the second quarter of 2010 and 2009 were 40.3% and 34.9%, respectively. The effective tax rate was higher as a result of a shift in earnings being generated from states with lower tax rates to states with higher tax rates.

Six Months of 2010 and 2009 Compared

We reported net income in the first six months of 2010 of $50.4 million, or $0.49 per share, compared to the first six months of 2010 of $73.1 million, or $0.71 per share. Net income decreased in the first half of 2010 by $22.7 million, primarily due to a decrease in operating revenues and an increase in operating expenses.

Operating revenues decreased by $30.7 million, largely due to decreases in natural gas production revenues offset by increases in crude oil and condensate revenues. Operating expenses increased by $9.7 million between periods due primarily to increases in depreciation, depletion and amortization, impairment of unproved properties and exploration expense offset by lower brokered costs and general and administration expenses. In addition, net income was impacted in the first half of 2009 by a loss on sale of assets as well as an increase in expenses of $1.5 million resulting from a combination of higher interest and other expenses and decreased income tax expense.

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Natural Gas Production Revenues

Our average total company realized natural gas production sales price, including the realized impact of derivative instruments, was $5.99 per Mcf for the six months ended June 30, 2010 compared to $7.38 per Mcf for the comparable period of the prior year. These prices include the realized impact of derivative instrument settlements, which increased the price by $1.29 per Mcf in 2010 and decreased the price by $3.74 per Mcf in 2009. The following table excludes the unrealized gain from the change in fair value of our basis swaps of $0.4 million for the six months ended June 30, 2009 and $0.8 million for the six months ended June 30, 2009, which have been included within Natural Gas Production Revenues in the Condensed Consolidated Statement of Operations.

	Six Months Ended June 30,		Variance	
	2010	**2009**	**Amount**	**Percent**
Natural Gas Production *(Mmcf)*				
North	**31,510**	22,577	8,933	40%
South	**22,843**	25,250	(2,407)	(10%)
Canada		958	(958)	(100%)
Total Company	**54,353**	48,785	5,568	11%
Natural Gas Production Sales Price *($/Mcf)*				
North	**$ 4.98**	$ 6.72	$ (1.74)	(26%)
South	**$ 7.38**	$ 8.12	$ (0.74)	(9%)
Canada	**$**	$ 3.40	$ (3.40)	(100%)
Total Company	**$ 5.99**	$ 7.38	$ (1.39)	(19%)
Natural Gas Production Revenue *(In thousands)*				
North	**$ 156,895**	$ 151,656	$ 5,239	3%
South	**168,592**	205,004	(36,412)	(18%)
Canada		3,258	(3,258)	(100%)
Total Company	**$ 325,487**	$ 359,918	$ (34,433)	(10%)
Price Variance Impact on Natural Gas Production Revenue *(In thousands)*				
North	**$ (54,765)**			
South	**(16,868)**			
Canada	**$**			
Total Company	**$ (71,633)**			
Volume Variance Impact on Natural Gas Production Revenue *(In thousands)*				
North	**$ 60,002**			
South	**(19,544)**			
Canada	**(3,258)**			
Total Company	**$ 37,200**			

The decrease in Natural Gas Production Revenue of $34.4 million, excluding the impact of the unrealized gain discussed above, is due to primarily to the decrease in realized natural gas prices in both the North and South regions, decreased production in the South region associated with normal production declines, delays in completions and a shift from gas to oil projects, as well as the sale of our Canadian properties in April 2009. Partially offsetting these decreases was an increase in natural gas production in the North region associated with increased drilling and the start up of the Lathrop compressor station in the Marcellus shale.

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Brokered Natural Gas Revenue and Cost

	Six Months Ended June 30, 2010	Six Months Ended June 30, 2009	Variance Amount	Variance Percent
Sales Price *($/Mcf)*	**$ 5.75**	$ 7.39	$ (1.64)	(22%)
Volume Brokered *(Mmcf)*	**x 6,644**	x 6,099	545	9%
Brokered Natural Gas Revenues *(In thousands)*	**$ 38,221**	$ 45,085		
Purchase Price *($/Mcf)*	**$ 4.98**	$ 6.63	$ (1.65)	(25%)
Volume Brokered *(Mmcf)*	**x 6,644**	x 6,099	545	9%
Brokered Natural Gas Cost *(In thousands)*	**$ 33,061**	$ 40,433		
Brokered Natural Gas Margin *(In thousands)*	**$ 5,160**	$ 4,652	$ 508	11%

(In thousands)	
Sales Price Variance Impact on Revenue	**$ (10,889)**
Volume Variance Impact on Revenue	**4,028**
	$ (6,861)

(In thousands)	
Purchase Price Variance Impact on Purchases	**$ 10,982**
Volume Variance Impact on Purchases	**(3,613)**
	$ 7,369

The increased brokered natural gas margin of $0.5 million is a result of an increase in volumes brokered, offset by decreases in sales and purchase price.

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Crude Oil and Condensate Revenues

Our average total company realized crude oil sales price, including the realized impact of derivative instruments, was $97.04 per Bbl for the first half of 2010 compared to $79.55 per Bbl for the first half of 2009. These prices include the realized impact of derivative instrument settlements, which increased the price by $22.09 in 2010 and $34.87 in 2009. There was no revenue impact from the unrealized change in crude oil and condensate derivative fair value for the six months ended June 30, 2009 and 2008.

	Six Months Ended June 30,		Variance	
	2010	**2009**	**Amount**	**Percent**
Crude Oil Production *(Mbbl)*				
North	**48**	55	(7)	(13%)
South	**377**	321	56	17%
Canada		6	(6)	(98%)
Total Company	**425**	383	42	11%
Crude Oil Sales Price *($/Bbl)*				
North	**$ 67.63**	$ 42.73	$ 24.88	58%
South	**$ 100.75**	$ 86.72	$ 14.02	16%
Canada	**$**	$ 36.46	$ (36.46)	(100%)
Total Company	**$ 97.04**	$ 79.55	$ 17.49	22%
Crude Oil Revenue *(In thousands)*				
North	**$ 3,258**	$ 2,350	$ 909	39%
South	**37,935**	27,838	10,097	36%
Canada		219	(219)	(100%)
Total Company	**$ 41,193**	$ 30,407	$ 10,787	35%
Price Variance Impact on Crude Oil Revenue *(In thousands)*				
North	**$ 1,210**			
South	**5,281**			
Canada				
Total Company	**$ 6,491**			
Volume Variance Impact on Crude Oil Revenue *(In thousands)*				
North	**$ (300)**			
South	**4,815**			
Canada	**(219)**			
Total Company	**$ 4,296**			

The $10.8 million increase in crude oil and condensate revenues is primarily due to an increase in realized crude oil prices in the North and South regions and an increase in crude oil production in the South regions. These increases are partially offset by lower production in the North region and Canada.

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Impact of Derivative Instruments on Operating Revenues

The following table reflects the realized impact of cash settlements and the net unrealized change in fair value of derivative instruments:

	Six Months Ended June 30,			
	2010		2009	
(In thousands)	Realized	Unrealized	Realized	Unrealized
Operating Revenues Increase / (Decrease) to Revenue				
Cash Flow Hedges				
Natural Gas Production	**$ 70,253**	**$**	$ 182,666	$
Crude Oil	**9,362**		13,356	
Total Cash Flow Hedges	**79,615**		196,022	
Other Derivative Financial Instruments				
Natural Gas Basis Swaps		**355**		815
Total Other Derivative Financial Instruments		**355**		815
Total Cash Flow Hedges and Other Derivative Financial Instruments	**$ 79,615**	**$ 355**	$ 196,022	$ 815

Operating Expenses

Total costs and expenses from operations increased by $9.7 million in the first six months of 2010 compared to the same period of 2009. The primary reasons for this fluctuation are as follows:

Depreciation, Depletion and Amortization increased by $15.1 million from the first half of 2009 compared to the first half of 2010. This is primarily due to a higher DD&A rate as a result of higher capital costs and increased equivalent production volumes.

Impairment of Unproved Properties increased $8.2 million primarily due to increased unproved leasehold costs in Susquehanna County and South Texas in late 2009 and early 2010.

Exploration expense increase $1.8 million primarily due to increased geological and geophysical costs and professional services fees partially offset by decreased delay rentals, other exploration expense and employee related costs.

Brokered Natural Gas Cost decreased by $7.4 million from the first half of 2010 compared to the first half of 2009. See the preceding table titled Brokered Natural Gas Revenue and Cost for further analysis.

General and Administrative expenses decreased by $5.6 million from the second first half of 2009 compared to the first half of 2010. This decrease is primarily due to lower stock compensation and pension and post retirement benefit expense, partially offset by increased salaries and wages, incentive compensation and professional service costs.

Gain on Sale of Assets

An aggregate gain of $5.1 million was recognized in the first half of 2010. During the first half of 2010, a gain of $10.3 million was recognized on the sale of the Woodford shale prospect, offset by an impairment charge of $5.8 million on assets held for sale. In the first half of 2009, a loss of $16.6 million was recognized primarily due to the sale of the our Canadian properties offset by a $12.7 million gain on sale of assets in the first quarter of 2009 primarily related to the sale of the Thornwood properties in the North region.

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Income Tax Expense

Income tax expense increased by $10.2 million in the first half of 2010 due to a higher effective tax rate partially offset by lower pre-tax income compared to the first half of 2009. The effective tax rates for the first half of 2010 and 2009 were 38.5% and 36.4%, respectively. The effective tax rate was higher as a result of a shift in earnings being generated from states with lower tax rates to states with higher tax rates.

Forward-Looking Information

The statements regarding future financial performance and results, market prices and the other statements which are not historical facts contained in this report are forward-looking statements. The words expect, project, estimate, believe, anticipate, intend, budget, plan, predict and similar expressions are also intended to identify forward-looking statements. Such statements involve risks and uncertainties, including, but not limited to, market factors, market prices (including regional basis differentials) of natural gas and crude oil, results for future drilling and marketing activity, future production and costs and other factors detailed herein and in our other Securities and Exchange Commission filings. Should one or more of these risks or uncertainties materialize, or should underlying assumptions prove incorrect, actual outcomes may vary materially from those indicated.

ITEM 3. Quantitative and Qualitative Disclosures about Market Risk

Market Risk

Our primary market risk is exposure to crude oil and natural gas prices. Realized prices are mainly driven by worldwide prices for crude oil and spot market prices for North American natural gas production. Commodity prices are volatile and unpredictable.

The debt and equity markets continue to experience unfavorable conditions, which may affect our ability to access those markets. As a result of the volatility and continued uncertainty in the capital markets and our increased level of borrowings, we may experience increased costs associated with future borrowings and debt issuances. We will continue to monitor events and circumstances surrounding each of our lenders in our revolving credit facility.

Derivative Instruments and Hedging Activity

Our hedging strategy is designed to reduce the risk of price volatility for our production in the natural gas and crude oil markets. A hedging committee that consists of members of senior management oversees our hedging activity. Our hedging arrangements apply to only a portion of our production and provide only partial price protection. These hedging arrangements limit the benefit to us in periods of increasing prices, but offer protection in the event of price declines. Further, if our counterparties defaulted, this protection might be limited as we might not receive the benefits of the hedges. Please read the discussion below as well as Note 7 of the Notes to the Condensed Consolidated Financial Statements for a more detailed discussion of our hedging arrangements.

As of June 30, 2010, we had 23 derivative contracts open: 15 natural gas price swap arrangements, six natural gas basis swaps and two crude oil price swap arrangements. During the first six months of 2010, the Company entered into five new derivative contracts covering anticipated crude oil production for 2010 and natural gas production for 2011.

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As of June 30, 2010, we had the following outstanding commodity derivatives:

Commodity and Derivative Type	Weighted-Average Contract Price		Volume		Contract Period	Net Unrealized Gain / (Loss) (In thousands)
Derivatives designated as Hedging Instruments						
Natural Gas Swap	$ 9.30	per Mcf	17,977	Mmcf	July - December 2010	$ 75,765
Natural Gas Swap	$ 6.26	per Mcf	12,909	Mmcf	January - December 2011	3,629
Crude Oil Swap	$ 104.25	per Bbl	366	Mbbl	July - December 2010	10,008
						$ 89,402
Derivatives not qualifying as Hedging Instruments						
Natural Gas Basis Swap	$ (0.27)	per Mcf	16,123	Mmcf	January - December 2012	$ (1,599)
						$ 87,803

The amounts set forth under the net unrealized gain column in the table above represent our total unrealized gain position at June 30, 2010 and include the impact of nonperformance risk. Nonperformance risk was primarily evaluated by reviewing credit default swap spreads for the various financial institutions in which we have derivative transactions.

From time to time, we enter into natural gas and crude oil swap agreements with counterparties to hedge price risk associated with a portion of our production. These cash flow hedges are not held for trading purposes. Under these price swaps, we receive a fixed price on a notional quantity of natural gas or crude oil in exchange for paying a variable price based on a market-based index, such as the NYMEX gas and crude oil futures.

During the first half of 2010, natural gas price swaps covered 17,879 Mmcf, or 33%, of our first half of 2010 gas production at an average price of $9.30 per Mcf.

We had two crude oil price swaps covering 364 Mbbl, or 85%, of our second quarter of 2010 oil production at an average price of $104.25 per Bbl.

We are exposed to market risk on these open contracts, to the extent of changes in market prices of natural gas and crude oil. However, the market risk exposure on these hedged contracts is generally offset by the gain or loss recognized upon the ultimate sale of the commodity that is hedged.

The preceding paragraphs contain forward-looking information concerning future production and projected gains and losses, which may be impacted both by production and by changes in the future market prices of energy commodities. See Forward-Looking Information for further details.

Fair Market Value of Financial Instruments

The estimated fair value of financial instruments is the amount at which the instrument could be exchanged currently between willing parties. The carrying amounts reported in the Condensed Consolidated Balance Sheet for cash and cash equivalents, accounts receivable, and accounts payable approximate fair value.

The fair value of long-term debt is the estimated cost to acquire the debt, including a credit spread for the difference between the issue rate and the period end market rate. The credit spread is our default or repayment risk. The credit spread (premium or discount) is determined by comparing our fixed-rate notes and credit facility to new issues (secured and unsecured) and secondary trades of similar size and credit statistics for both public and private debt. The fair value of all of the fixed-rate notes and credit facility is based on interest rates currently available to us.

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We use available marketing data and valuation methodologies to estimate the fair value of debt.

	June 30, 2010		December 31, 2009	
(In thousands)	Carrying Amount	Estimated Fair Value	Carrying Amount	Estimated Fair Value
Long-Term Debt	**$ 1,015,000**	**$ 1,134,677**	$ 805,000	$ 863,559

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ITEM 4. Controls and Procedures

As of the end of the current reported period covered by this report, the Company carried out an evaluation, under the supervision and with the participation of the Company s management, including the Company s Chief Executive Officer and Chief Financial Officer, of the effectiveness of the design and operation of the Company s disclosure controls and procedures pursuant to Rules 13a-15 and 15d-15 of the Securities Exchange Act of 1934 (the Exchange Act). Based upon that evaluation, the Chief Executive Officer and Chief Financial Officer concluded that the Company s disclosure controls and procedures are effective at a reasonable assurance level with respect to the recording, processing, summarizing and reporting, within the time periods specified in the Commission s rules and forms, of information required to be disclosed by the Company in the reports that it files or submits under the Exchange Act.

There were no changes in the Company s internal control over financial reporting that occurred during the second quarter of 2010 that have materially affected, or are reasonably likely to materially affect, the Company s internal control over financial reporting.

PART II. OTHER INFORMATION

ITEM 1. Legal Proceedings

The information set forth under the heading Environmental Matters in Note 6 of the Notes to Condensed Consolidated Financial Statements included in Item 1 of Part I of this quarterly report is incorporated by reference in response to this item.

ITEM 1A. Risk Factors

For additional information about the risk factors facing the Company, see Item 1A of Part I of the Company s Annual Report on Form 10-K for the year ended December 31, 2009.

ITEM 2. Unregistered Sales of Equity Securities and Use of Proceeds

Issuer Purchases of Equity Securities

The Board of Directors has authorized a share repurchase program under which the Company may purchase shares of common stock in the open market or in negotiated transactions. There is no expiration date associated with the authorization. During the three months ended June 30, 2010, the Company did not repurchase any shares of common stock. All purchases executed to date have been through open market transactions. The maximum number of shares that may yet be purchased under the plan as of June 30, 2010 was 4,795,300.

ITEM 6. Exhibits

Exhibit Number	Description
4.1	Note Purchase Agreement dated as of July 26, 2001 among Cabot Oil & Gas Corporation and the Purchasers listed therein (Form 8-K for August 30, 2001).
	(a) Amendment No. 1 to Note Purchase Agreement, dated as of June 30, 2010.
4.2	Note Purchase Agreement dated as of July 16, 2008 among Cabot Oil & Gas Corporation and the Purchasers named therein (Form 8-K for July 16, 2008).

(a) Amendment No. 1 to Note Purchase Agreement, dated as of June 30, 2010.

4.3 Note Purchase Agreement dated as of December 1, 2008 among Cabot Oil & Gas Corporation and the Purchasers named therein (Form 10-K for 2008)

(a) Amendment No. 1 to Note Purchase Agreement, dated as of June 30, 2010.

4.5 Credit Agreement, dated as of April 24, 2009, among the Company, JPMorgan Chase Bank, N.A., as Administrative Agent, Banc of America Securities LLC, as Syndication Agent, Bank of Montreal, as Documentation Agent, and the Lenders party thereto (Form 8-K for April 24, 2009).

(a) First Amendment to Credit Agreement, dated as of June 17, 2010.

15.1 Awareness letter of PricewaterhouseCoopers LLP

31.1 302 Certification - Chairman, President and Chief Executive Officer

31.2	302 Certification - Vice President, Chief Financial Officer and Treasurer
32.1	906 Certification
*101.INS	XBRL Instance Document
*101.SCH	XBRL Taxonomy Extension Schema Document
*101.CAL	XBRL Taxonomy Extension Calculation Linkbase Document
*101.LAB	XBRL Taxonomy Extension Label Linkbase Document
*101.PRE	XBRL Taxonomy Extension Presentation Linkbase Document

* Furnished, not filed. Users of this data submitted electronically herewith 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, is deemed not filed for purposes of section 18 of the Securities Exchange Act of 1934, and otherwise is not subject to liability under these sections.

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SIGNATURES

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

	CABOT OIL & GAS CORPORATION (Registrant)
July 30, 2010	By: /s/ DAN O. DINGES **Dan O. Dinges** **Chairman, President and** **Chief Executive Officer** **(Principal Executive Officer)**
July 30, 2010	By: /s/ SCOTT C. SCHROEDER **Scott C. Schroeder** **Vice President, Chief Financial Officer and Treasurer** **(Principal Financial Officer)**
July 30, 2010	By: /s/ TODD M. ROEMER **Todd M. Roemer** **Controller** **(Principal Accounting Officer)**