HARTFORD FINANCIAL SERVICES GROUP INC/DE
Form 8-K
May 12, 2003

UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, DC 20549

FORM 8-K

CURRENT REPORT
Pursuant to Section 13 or 15(d) of the Securities Exchange Act of 1934

Date of Report (Date of earliest event reported): May 12, 2003

THE HARTFORD FINANCIAL SERVICES GROUP, INC.
(Exact name of registrant as specified in its charter)

Delaware	0-19277	13-3317783
(State or other jurisdiction of Incorporation)	(Commission File Number)	(IRS Employer Identification No.)

The Hartford Financial Services Group, Inc.
Hartford Plaza
Hartford, Connecticut 06115-1900
(Address of principal executive offices) (Zip Code)

Registrant's telephone number, including area code: (860) 547-5000

Item 7. Financial Statements and Exhibits.

(a) Financial statements of business acquired. Not applicable.

(b) Pro forma financial information. Not applicable.

(c) Exhibits. The exhibits listed below are being furnished with this Form 8-K:

Exhibit 99.1 Press Release dated as of May 12, 2003 entitled, "The Hartford Announces Asbestos Results and Capital Plan"

Exhibit 99.2 Press Release dated as of May 12, 2003 entitled, "The Hartford Pre-Announces First Quarter Results"

Item 9. Regulation FD Disclosure.

In accordance with the procedural guidance set forth in SEC Release No. 33-8216, the following information and the attached exhibits are being furnished under "Item 9. Regulation FD Disclosure" in satisfaction of the requirements of "Item 12. Results of Operations and Financial Condition" as well as "Item 9. Regulation FD Disclosure."

On May 12, 2003, The Hartford Financial Services Group, Inc. issued a press release announcing the results of its comprehensive asbestos study and its capital and cost plan. A copy of the press release is furnished herewith as Exhibit 99.1 and is incorporated herein by reference.

On May 12, 2003, The Hartford Financial Services Group, Inc. issued a press release pre-announcing its first quarter results. A copy of the press release is furnished herewith as Exhibit 99.2 and is incorporated herein by reference.

As provided in General Instructions B.2 and B.6 of Form 8-K, the information and exhibits contained in this Form 8-K shall not be deemed to be "filed" for purposes of Section 18 of the Securities Exchange Act of 1934, as amended, nor shall they be deemed to be incorporated by reference in any filing under the Securities Act of 1933, as amended, except as shall be expressly set forth by specific reference in such a filing.

SIGNATURE

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 hereunto duly authorized.

THE HARTFORD FINANCIAL SERVICES GROUP, INC.

Date: May 12, 2003

By: /s/ NEAL S. WOLIN

Name: Neal S. Wolin
Title: Executive Vice President and General Counsel

552,877 (ii) shared power to vote or to direct the vote __________ (iii) sole power to dispose or to direct the disposition of 552,877 (iv) shared power to dispose or to direct the disposition of __________ Item 5 Ownership of Five Percent or Less of a Class. [ ] Item 6 Ownership of More than Five Percent on Behalf of Another Person . NONE Item 7 Identification and Classification of the Subsidiary Which Acquired The Security Being Reported on by the Parent Holding Company. NOT APPLICABLE Item 8 Identification and Classification of Members of the Group. NOT APPLICABLE Item 9 Notice of Dissolution of Group. NOT APPLICABLE CUSIP No. 50047H201 13G Item 10 Certification. By signing below I certify that, to the best of my knowledge and belief, the securities referred to above were acquired and are held in the ordinary course of business and were not acquired and are not held for the purpose of or with the effect of changing or influencing the control of the issuer of the securities and were not acquired and are not held in connection with or as a participant in any transaction having that purpose or effect. Signature After reasonable inquiry and to the best of my knowledge and belief, I certify that the information set forth in this statement with respect to it is true, complete and correct. Date: January 13, 2012 By: John E. Denneen, Secretary **Three Months Ended June 30,** **Six Months Ended June 30,**

(In thousands, except per share amounts)

2011	**2010**	**2011**	**2010**

OPERATING REVENUES

Natural Gas

$200,357 $164,528 **$370,455** $334,399

Brokered Natural Gas

11,072 13,348 **29,480** 38,221

Crude Oil and Condensate

28,042 21,211 **46,634** 41,193

Other

1,225 1,154 **3,153** 2,774 **240,696** 200,241 **449,722** 416,587

OPERATING EXPENSES

Brokered Natural Gas Cost

9,796 11,793 **25,158** 33,061

Direct Operations

22,579 24,347 **49,586** 47,330

Transportation and Gathering

16,074 4,767 **28,942** 8,557

Taxes Other Than Income

5,877 11,841 **14,028** 22,646

Exploration

4,592 10,233 **10,900** 18,659

Depreciation, Depletion and Amortization

83,225 76,726 **160,349** 150,224

General and Administrative

26,006 12,853 **50,305** 28,599 **168,149** 152,560 **339,268** 309,076

Gain / (Loss) on Sale of Assets

34,071 4,387 **32,554** 5,146

INCOME FROM OPERATIONS

	106,618	52,068	**143,008**	112,657
Interest Expense and Other	**18,044**	15,769	**35,411**	30,681
Income Before Income Taxes	**88,574**	36,299	**107,597**	81,976
Income Tax Expense	**33,897**	14,617	**40,034**	31,598
NET INCOME	**$54,677**	$21,682	**$67,563**	$ 50,378
Earnings Per Share				
Basic	**$0.53**	$0.21	**$0.65**	$0.49
Diluted	**$0.52**	$0.21	**$0.64**	$0.48
Weighted-Average Shares Outstanding				
Basic	**104,264**	103,915	**104,204**	103,855
Diluted	**105,337**	104,964	**105,088**	104,838
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, 2011	December 31, 2010
ASSETS		
Current Assets		
Cash and Cash Equivalents	**$ 39,314**	$ 55,949
Accounts Receivable, Net	**117,314**	94,488
Income Taxes Receivable	**7,893**	
Inventories	**24,044**	29,667
Deferred Income Taxes		257
Derivative Instruments	**40,344**	16,926
Other Current Assets	**6,929**	5,721
Total Current Assets	**235,838**	203,008
Properties and Equipment, Net (Successful Efforts Method)	**3,967,716**	3,762,760
Other Assets	**46,606**	39,263
	$ 4,250,160	$ 4,005,031
LIABILITIES AND STOCKHOLDERS EQUITY		
Current Liabilities		
Accounts Payable	**$ 223,838**	$ 229,981
Income Taxes Payable		25,957
Deferred Income Taxes	**9,778**	
Accrued Liabilities	**53,108**	47,897
Total Current Liabilities	**286,724**	303,835
Pension and Postretirement Benefits	**34,869**	34,053
Long-Term Debt	**1,095,000**	975,000
Deferred Income Taxes	**757,612**	714,953
Asset Retirement Obligation	**74,048**	72,311
Other Liabilities	**35,708**	32,179
Total Liabilities	**2,283,961**	2,132,331
Commitments and Contingencies		
Stockholders Equity		
Common Stock:		
Authorized 240,000,000 Shares of $0.10 Par Value in 2011 and 2010 Issued 104,467,059 Shares and 104,210,084 Shares in 2011 and 2010, respectively	**10,447**	10,421
Additional Paid-in Capital	**727,021**	720,920
Retained Earnings	**1,209,705**	1,148,391
Accumulated Other Comprehensive Income/(Loss)	**22,375**	(3,683)
Less Treasury Stock, at Cost:		
202,200 Shares in 2011 and 2010, respectively	**(3,349)**	(3,349)
Total Stockholders Equity	**1,966,199**	1,872,700
	$ 4,250,160	$ 4,005,031

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, 2011	2010
CASH FLOWS FROM OPERATING ACTIVITIES		
Net Income	**$ 67,563**	$ 50,378
Adjustments to Reconcile Net Income to Cash Provided by Operating Activities:		
Depreciation, Depletion and Amortization	**160,349**	150,224
Deferred Income Tax Expense	**36,886**	29,091
(Gain) / Loss on Sale of Assets	**(32,554)**	(5,146)
Exploration Expense	**504**	8,426
Unrealized Loss / (Gain) on Derivative Instruments	**886**	(355)
Amortization of Debt Issuance Costs	**2,253**	2,136
Stock-Based Compensation Expense and Other	**19,576**	6,219
Changes in Assets and Liabilities:		
Accounts Receivable, Net	**(22,826)**	1,200
Income Taxes	**(33,850)**	5,083
Inventories	**5,623**	4,456
Other Current Assets	**(1,208)**	1,061
Accounts Payable and Accrued Liabilities	**10,821**	(5,937)
Other Assets and Liabilities	**6,678**	(3,658)
Net Cash Provided by Operating Activities	**220,701**	243,178
CASH FLOWS FROM INVESTING ACTIVITIES		
Capital Expenditures	**(404,214)**	(454,143)
Proceeds from Sale of Assets	**54,336**	16,742
Net Cash Used in Investing Activities	**(349,878)**	(437,401)
CASH FLOWS FROM FINANCING ACTIVITIES		
Borrowings from Debt	**220,000**	210,000
Repayments of Debt	**(100,000)**	
Dividends Paid	**(6,250)**	(6,228)
Capitalized Debt Issuance Costs	**(1,025)**	(1,986)
Other	**(183)**	(36)
Net Cash Provided by Financing Activities	**112,542**	201,750
Net (Decrease) / Increase in Cash and Cash Equivalents	**(16,635)**	7,527
Cash and Cash Equivalents, Beginning of Period	**55,949**	40,158
Cash and Cash Equivalents, End of Period	**$ 39,314**	$ 47,685

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, 2010 (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 with current year presentation. These reclassifications have no impact on previously reported net income.

With respect to the unaudited financial information of the Company as of June 30, 2011 and for the three and six months ended June 30, 2011 and 2010, 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 29, 2011 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 Issued Accounting Pronouncements

In May 2011, the Financial Accounting Standards Board (FASB) issued ASU No. 2011-04, Amendments to Achieve Common Fair Value Measurement and Disclosure Requirements in U.S. GAAP and IFRSs. The amendments in this Update generally represent clarifications of Topic 820, but also include some instances where a particular principle or requirement for measuring fair value or disclosing information about fair value measurements has changed. This Update results in common principles and requirements for measuring fair value and for disclosing information about fair value measurements in accordance with U.S. GAAP and IFRSs. The amendments in this Update are to be applied prospectively. For public entities, the amendments are effective during interim and annual periods beginning after December 15, 2011. Early application by public entities is not permitted. The Company does not expect this guidance to have a significant impact on our consolidated financial position, results of operations or cash flows.

In June 2011, the FASB issued Accounting Standards Update (ASU) No. 2011-05, Presentation of Comprehensive Income, requiring most entities to present items of net income and other comprehensive income either in one continuous statement referred to as the statement of comprehensive income or in two separate, but consecutive, statements of net income and other comprehensive income. The new requirements are effective for public entities for fiscal years (including interim periods) beginning after December 15, 2011. The Company does not expect this guidance to have a significant impact on our consolidated financial position, results of operations or cash flows.

2. PROPERTIES AND EQUIPMENT, NET

Properties and equipment, net are comprised of the following:

(In thousands)	June 30, 2011	December 31, 2010
Proved Oil and Gas Properties	**$ 5,152,151**	$ 4,794,650
Unproved Oil and Gas Properties	**492,258**	490,181
Gathering and Pipeline Systems	**237,333**	237,043
Land, Building and Other Equipment	**78,943**	86,248
	5,960,685	5,608,122

Accumulated Depreciation, Depletion and Amortization	**(1,992,969)**	(1,845,362)
	$ 3,967,716	$ 3,762,760

At June 30, 2011, 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.

CABOT OIL & GAS CORPORATION

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

Haynesville/Bossier Shale Joint Ventures

During the first six months of 2011, the Company entered into two participation agreements with third parties related to certain of its Haynesville and Bossier Shale leaseholds in East Texas. Under the terms of the participation agreements, the third parties will fund 100% of the cost to drill and complete certain Haynesville and Bossier Shale wells in the related leaseholds over a multi-year period in exchange for a 75% working interest in the leaseholds. During the first six months of 2011, Cabot received a reimbursement of drilling costs of approximately $11.2 million associated with the participation agreements.

In May 2011, the Company sold certain of its Haynesville and Bossier Shale oil and gas properties in East Texas to a third party. The Company received approximately $47.0 million in cash proceeds and recognized a $34.2 million gain on sale of assets.

Other Divestitures

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 in Colorado, an impairment loss of approximately $5.8 million was recognized. The impairment charge was included in Gain / (Loss) on Sale of Assets in the Condensed Consolidated Statement of Operations. Fair value of the impaired properties 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 these properties were considered level 2 in the fair value hierarchy.

Subsequent Event

In July 2011, the Company entered into a purchase and sale agreement to sell certain oil and gas properties located in Colorado, Utah and Wyoming for $285 million in cash. This transaction is expected to close in the fourth quarter 2011, subject to customary closing conditions and adjustments.

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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, 2011	December 31, 2010
ACCOUNTS RECEIVABLE, NET		
Trade Accounts	$ 109,924	$ 91,077
Joint Interest Accounts	10,368	4,901
Other Accounts	759	2,603
	121,051	98,581
Allowance for Doubtful Accounts	(3,737)	(4,093)
	$ 117,314	$ 94,488
INVENTORIES		
Natural Gas in Storage	$ 10,605	$ 13,371
Tubular Goods and Well Equipment	12,941	17,072
Pipeline Imbalances	498	(776)
	$ 24,044	$ 29,667
OTHER CURRENT ASSETS		
Drilling Advances	$ 25	$ 2,796
Prepaid Balances	4,670	2,925
Restricted Cash	2,234	
	$ 6,929	$ 5,721
OTHER ASSETS		
Rabbi Trust Deferred Compensation Plan	16,231	15,788
Debt Issuance Costs	19,808	22,061
Derivative Instruments	9,231	
Other Accounts	1,336	1,414
	$ 46,606	$ 39,263
ACCOUNTS PAYABLE		
Trade Accounts	$ 24,758	$ 27,401
Natural Gas Purchases	7,519	3,596
Royalty and Other Owners	47,956	36,034
Accrued Capital Costs	129,652	146,824
Taxes Other Than Income	(219)	2,655
Drilling Advances	498	523
Wellhead Gas Imbalances	4,376	5,142
Other Accounts	9,298	7,806

	$ 223,838	$ 229,981
ACCRUED LIABILITIES		
Employee Benefits	**$ 8,475**	$ 10,790
Pension and Postretirement Benefits	**1,688**	1,688
Taxes Other Than Income	**15,695**	14,576
Interest Payable	**24,915**	19,488
Derivative Instruments	**1,160**	
Other Accounts	**1,175**	1,355
	$ 53,108	$ 47,897
OTHER LIABILITIES		
Rabbi Trust Deferred Compensation Plan	**$ 26,399**	$ 21,600
Derivative Instruments		2,180
Other Accounts	**9,309**	8,399
	$ 35,708	$ 32,179

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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, 2011	December 31, 2010
Long-Term Debt		
7.33% Weighted-Average Fixed Rate Notes	**$ 95,000**	$ 95,000
6.51% Weighted-Average Fixed Rate Notes	**425,000**	425,000
9.78% Notes	**67,000**	67,000
5.58% Weighted-Average Fixed Rate Notes	**175,000**	175,000
Credit Facility	**333,000**	213,000
	$ 1,095,000	$ 975,000

Effective April 1, 2011, the lenders under the Company s revolving credit facility approved an increase in the Company s Borrowing Base from $1.5 billion to $1.7 billion as part of the annual redetermination under the terms of the credit facility.

At June 30, 2011, the Company had $333.0 million of borrowings outstanding under its revolving credit facility at a weighted-average interest rate of 4.3% and $566.8 million available for future borrowings. In addition, the Company had letters of credit outstanding at June 30, 2011 of $0.3 million.

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, 2011 and 2010:

	Three Months Ended June 30,		Six Months Ended June 30,	
(In thousands)	2011	2010	2011	2010
Weighted-Average Shares Basic	**104,264**	103,915	**104,204**	103,855
Dilution Effect of Stock Options, Stock Appreciation Rights and Stock Awards at End of Period	**1,073**	1,049	**884**	983
Weighted-Average Shares Diluted	**105,337**	104,964	**105,088**	104,838
Weighted-Average Stock Awards and Shares Excluded from Diluted Earnings per Share due to the Anti-Dilutive Effect	**1**	634	**72**	429

6. COMMITMENTS AND CONTINGENCIES

Contingencies

The Company is a defendant in various legal proceedings arising in the normal course of 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.

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 the PaDEP reached agreement on modifications to the Consent Order (First Modified Consent Order). In the First Modified Consent Order, the PaDEP and the Company agreed that the Company will provide a permanent source

CABOT OIL & GAS CORPORATION

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

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 until all obligations under the consent orders are fulfilled. In addition, the Company agreed to take certain other actions if requested by the PaDEP, which could include the plugging and abandonment of up to 10 additional wells. 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.

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. No penalties were assessed under the Second Modified Consent Order.

As required by the Second Modified Consent Order, the Company made offers to provide whole-house water treatment systems to the 14 households. As required by the First Modified Consent Order, on August 5, 2010 the Company filed with the PaDEP its report, prepared by its experts, finding that the Company s well drilling and development activities are not the source of methane gas reported to be in the groundwater and water wells in the area of concern.

Despite the Company s vigorous efforts to comply with the various consent orders, in a September 14, 2010 letter to the Company, the PaDEP rejected the Company s expert report and determined that the Company s drilling activities continue to cause the unpermitted discharge of natural gas into the groundwater and continue to affect residential water supplies in the area of concern. The PaDEP directed the Company, in accordance with the First Modified Consent Order, to plug or take other remedial actions at the remaining 10 wells and to contact the PaDEP to discuss connecting the impacted water supplies into a community public water system to permanently eliminate the continuing adverse affect to those water supplies.

The Company believed that it was in full compliance with the various consent orders. In a September 28, 2010 reply letter to the PaDEP, the Company disagreed with the PaDEP s rejection of the Company s expert report, disagreed that the remaining 10 wells continue to impact groundwater and affect residential water supplies and disagreed that a community public water system is necessary or feasible. The Company believed that offering installation of a whole-house water treatment system to the 14 households constituted compliance with the Company s obligations under these consent orders.

On December 15, 2010, the Company entered a global settlement agreement and new consent order with the PaDEP (Global Settlement Agreement), which supersedes the Consent Order, the First Modified Consent Order and the Second Modified Consent Order. Under the Global Settlement Agreement, among other things, the Company agreed to pay a total of $4.2 million into separate escrow accounts for the benefit of each affected household, pay $500,000 to the PaDEP to reimburse the PaDEP for its costs, remediate two wells in the affected area, provide pressure, water quality and well headspace data to the PaDEP and offer water treatment to the affected households. The Global Settlement Agreement settles all outstanding issues and claims that are known and that could have been brought against the Company by the PaDEP relating to the wells in the affected area and the Consent Order, the First Modified Consent Order and the Second Modified Consent Order. It also allows the Company to begin hydraulic fracturing in the affected areas after providing the PaDEP with well pressure data and to commence drilling new wells in the affected area in the second quarter of 2011. Under the Global Settlement Agreement, the Company has no obligation to connect the impacted water supplies to a community public water system.

As of the date of this report, the Company is in continuing discussions with the PaDEP to address the results of our well pressure tests, water quality sampling and well headspace screenings. We have requested PaDEP approval to resume hydraulic fracturing and new well drilling operations in the affected area.

On January 11, 2011, certain of the affected households appealed the Global Settlement Agreement to the Pennsylvania Environmental Hearing Board. A hearing on the merits of this appeal is not expected to occur until 2012.

As of June 30, 2011, the Company has paid $1.3 million in fines and penalties to the PaDEP related to this matter, paid $2.0 million to seven of the affected households and accrued a $2.2 million settlement liability that represents the unpaid escrow balance, which is included in Other Liabilities in the Condensed Consolidated Balance Sheet.

Transportation Agreements

During the first half of 2011, the Company amended certain gas transportation and gathering agreements with third party pipelines that increased the minimum daily quantity, increased the transportation fee and/or extended the term of the agreement.

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

Future minimum obligations under gas transportation agreements as of June 30, 2011 are as follows:

(In thousands)	
2011	$ 25,562
2012	55,882
2013	55,816
2014	55,816
2015	55,816
Thereafter	548,898
	$ **797,790**

For further information on the Company s gas transportation agreements, please refer to Note 8 of the Notes to the Consolidated Financial Statements in the Form 10-K.

Drilling Rig Commitments

As of June 30, 2011, the Company does not have any outstanding drilling commitments with initial terms greater than one year.

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, 2011, the Company had 42 derivative contracts open: 27 natural gas price swap arrangements, five natural gas collar arrangements, six natural gas basis swaps, one crude oil price collar arrangement and three crude oil price swap arrangements. During the first half of 2011, the Company entered into 31 new derivative contracts covering anticipated natural gas and crude oil production for 2011, 2012 and 2013.

As of June 30, 2011, 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 Swaps	$6.24	per Mcf	6,508	Mmcf	Jul. 2011 - Dec. 2011
Natural Gas Swaps	$5.18	per Mcf	118,049	Mmcf	Jul. 2011 - Dec. 2012
Natural Gas Swaps	$5.28	per Mcf	17,854	Mmcf	Jan. 2012 - Dec. 2012
Natural Gas Collars	$6.17 Ceiling/$5.13 Floor	per Mcf	17,805	Mmcf	Jan. 2013 - Dec. 2013
Crude Oil Collars	$93.25 Ceiling /$80.00 Floor	per Bbl	184	Mbbl	Jul. 2011 - Dec. 2011
Crude Oil Swaps	$106.20	per Bbl	184	Mbbl	Jul. 2011 - Dec. 2011
Crude Oil Swaps	$105.00	per Bbl	366	Mbbl	Jan. 2012 - Dec. 2012
Derivatives Not Designated as Hedging Instruments					
Natural Gas Basis Swaps	$(0.27)	per Mcf	16,123	Mmcf	Jan. 2012 - Dec. 2012

The change in fair value of derivatives designated as hedges that is effective is recorded to Accumulated Other Comprehensive Income / (Loss) in Stockholders Equity in the Condensed Consolidated Balance Sheet. The ineffective portion of the change in 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 Revenue and Crude Oil and Condensate Revenue, as appropriate, in the Condensed Consolidated Statement of Operations.

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CABOT OIL & GAS CORPORATION

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

The following schedules reflect the fair value 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, 2011	December 31, 2010
Derivatives Designated as Hedging Instruments			
Commodity Contracts	Derivative Instruments (current assets)	**41,886**	$ 16,926
Commodity Contracts	Accrued Liabilities	**(1,160)**	
Commodity Contracts	Other Assets	**10,755**	
		51,481	16,926
Derivatives Not Designated as Hedging Instruments			
Commodity Contracts	Derivative Instruments (current assets)	**(1,542)**	
Commodity Contracts	Other Assets	**(1,524)**	
Commodity Contracts	Other Liabilities		(2,180)
		(3,066)	(2,180)
		$ 48,415	$ 14,746

At June 30, 2011 and December 31, 2010, unrealized gains of $51.5 million ($31.9 million, net of tax) and $16.9 million ($10.5 million, net of tax), respectively, were recorded in Accumulated Other Comprehensive Income / (Loss). Based upon estimates at June 30, 2011, the Company expects to reclassify $25.3 million in after-tax income associated with its commodity hedges from Accumulated Other Comprehensive Income / (Loss) to the Condensed Consolidated Statement of Operations over the next 12 months.

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)	2011	2010	2011	2010	(In thousands)	2011	2010	2011	2010
Commodity Contracts	**$ 48,314**	$ (2,071)	**$ 60,887**	$ 54,756	Natural Gas Revenues	**$ 13,667**	$ 41,812	**$ 27,148**	$ 70,253
					Crude Oil and Condensate Revenues	(514)	4,779	(816)	9,362
						$ 13,153	$ 46,591	**$ 26,332**	$ 79,615

For the three and six months ended June 30, 2011 and 2010, respectively, there was no ineffectiveness recorded in our Condensed Consolidated Statement of Operations related to our derivative instruments.

Derivatives Not Designated as Hedging Instruments (In thousands)	**Location of Gain (Loss) Recognized in Income on Derivative**	**Three Months Ended June 30,**		**Six Months Ended June 30,**	
		2011	**2010**	**2011**	**2010**
Commodity Contracts	Natural Gas Revenues	**$ (903)**	$ 942	**$ (886)**	$ 355

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.

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CABOT OIL & GAS CORPORATION

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

8. FAIR VALUE MEASUREMENTS

Accounting Standards Codification (ASC) 820, Fair Value Measurements and Disclosures, 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. ASC 820 establishes formal fair value hierarchy 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 14 of the Notes to the Consolidated Financial Statements in the Form 10-K.

Non-Financial Assets and Liabilities

The Company discloses or recognizes its non-financial assets and liabilities, such as 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, 2011 and 2010 and no other fair value measurements were required to be recognized on a non-recurring basis, additional disclosures are 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, 2011 and December 31, 2010:

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CABOT OIL & GAS CORPORATION

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

(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, 2011
Assets				
Rabbi Trust Deferred Compensation Plan	$ 16,231	$	$	**$ 16,231**
Derivative Contracts			49,575	**49,575**
Total Assets	$ 16,231	$	$ 49,575	**$ 65,806**
Liabilities				
Rabbi Trust Deferred Compensation Plan	$ 26,399	$	$	**$ 26,399**
Derivative Contracts			1,160	**1,160**
Total Liabilities	$ 26,399	$	$ 1,160	**$ 27,559**

(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 December 31, 2010
Assets				
Rabbi Trust Deferred Compensation Plan	$ 15,788	$	$	$ 15,788
Derivative Contracts			16,926	16,926
Total Assets	$ 15,788	$	$ 16,926	$ 32,714
Liabilities				
Rabbi Trust Deferred Compensation Plan	$ 21,600	$	$	$ 21,600
Derivative Contracts			2,180	2,180
Total Liabilities	$ 21,600	$	$ 2,180	$ 23,780

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 non-performance risk of its counterparties by reviewing credit default swap spreads for the various financial institutions in which it has derivative transactions, while non-performance risk of the Company is evaluated using a market credit spread provided by the Company s bank. As of both June 30, 2011 and December 31, 2010, the impact of non-performance risk relative to the Company s derivative contracts was $0.1 million.

The following table sets forth a reconciliation of changes for the three- and six-month periods ended June 30, 2011 and 2010 in the fair value of financial assets and liabilities classified as Level 3 in the fair value hierarchy:

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CABOT OIL & GAS CORPORATION

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

(In thousands)	Three Months Ended June 30, 2011	Three Months Ended June 30, 2010	Six Months Ended June 30, 2011	Six Months Ended June 30, 2010
Balance at beginning of period	**$ 14,158**	$ 135,532	**$ 14,746**	$ 112,307
Total Gains or (Losses) (Realized or Unrealized):				
Included in Earnings [(1)]	**12,249**	47,534	**25,446**	79,972
Included in Other Comprehensive Income	**35,161**	(48,672)	**34,555**	(24,861)
Settlements	**(13,153)**	(46,591)	**(26,332)**	(79,615)
Transfers In and/or Out of Level 3				
Balance at end of period	**$ 48,415**	$ 87,803	**$ 48,415**	$ 87,803

(1) *A loss of $0.9 million the three and six months ended June 30, 2011, respectively, and and a gain of $0.9 million and $0.4 million for the three and six months ended June 30, 2010, respectively, was unrealized and included in Natural Gas Revenues in the Condensed Consolidated Statement of Operations.*

There were no transfers between Level 1 and Level 2 measurements for the three and six months ended June 30, 2011 and 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:

(In thousands)	June 30, 2011 Carrying Amount	June 30, 2011 Estimated Fair Value	December 31, 2010 Carrying Amount	December 31, 2010 Estimated Fair Value
Long-Term Debt	**$ 1,095,000**	**$ 1,231,089**	$ 975,000	$ 1,100,830

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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/(Loss). The following tables illustrate the calculation of Comprehensive Income/(Loss) for the three and six months ended June 30, 2011 and 2010:

		Three Months Ended June 30,		
(In thousands)		**2011**		**2010**
Net Income		**$ 54,677**		$ 21,682
Other Comprehensive Income / (Loss), net of taxes:				
Reclassification Adjustment for Settled Contracts, net of taxes of $4,998 and $17,219, respectively		**(8,155)**		(29,372)
Changes in Fair Value of Hedge Positions, net of taxes of $(18,331) and $325, respectively		**29,983**		(1,746)
Defined Benefit Pension and Postretirement Plans:				
Amortization of Net Obligation at Transition, net of taxes of $(59) and $(61), respectively	**99**		97	
Amortization of Prior Service Cost, net of taxes of $(117) and $(9), respectively	**199**		12	
Amortization of Net Loss, net of taxes of $(1,194) and $(257), respectively	**2,009**	**2,307**	396	505
Foreign Currency Translation Adjustment, net of taxes of $3 and $41, respectively		**(6)**		(107)
Total Other Comprehensive Income / (Loss)		**24,129**		(30,720)
Comprehensive Income / (Loss)		**$ 78,806**		$ (9,038)

		Six Months Ended June 30,		
(In thousands)		**2011**		**2010**
Net Income		**$ 67,563**		$ 50,378
Other Comprehensive Income / (Loss), net of taxes:				
Reclassification Adjustment for Settled Contracts, net of taxes of $10,006 and $29,537, respectively		**(16,326)**		(50,078)
Changes in Fair Value of Hedge Positions, net of taxes of $(23,109) and $(21,122), respectively		**37,778**		33,634
Defined Benefit Pension and Postretirement Plans:				
Amortization of Net Obligation at Transition, net of taxes of $(118) and $(120), respectively	**198**		196	
Amortization of Prior Service Cost, net of taxes of $(235) and $(15), respectively	**398**		27	
Amortization of Net Loss, net of taxes of $(2,388) and $(570), respectively	**4,018**	**4,614**	928	1,151
Foreign Currency Translation Adjustment, net of taxes of $3 and $(41), respectively		**(8)**		120

Total Other Comprehensive Income / (Loss)	**26,058**	(15,173)
Comprehensive Income / (Loss)	**$ 93,621**	$ 35,205

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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/ (Loss), net of taxes, for the six months ended June 30, 2011 were as follows:

(In thousands)	Net Gains / (Losses) on Cash Flow Hedges	Defined Benefit Pension and Postretirement Plans	Foreign Currency Translation Adjustment	Total
Balance at December 31, 2010	$ 10,494	$ (14,122)	$ (55)	$ (3,683)
Net change in unrealized gain on cash flow hedges, net of taxes of ($13,103)	21,452			21,452
Net change in defined benefit pension and postretirement plans, net of taxes of ($2,741)		4,614		4,614
Change in foreign currency translation adjustment, net of taxes of $3			(8)	(8)
Balance at June 30, 2011	**$ 31,946**	**$ (9,508)**	**$ (63)**	**$ 22,375**

10. PENSION AND OTHER POSTRETIREMENT BENEFITS

The components of net periodic benefit costs for the three and six months ended June 30, 2011 and 2010 were as follows:

(In thousands)	Three Months Ended June 30, 2011	Three Months Ended June 30, 2010	Six Months Ended June 30, 2011	Six Months Ended June 30, 2010
Qualified and Non-Qualified Pension Plans				
Current Period Service Cost	**$**	$ 896	**$**	$ 1,794
Interest Cost	**800**	993	**1,601**	1,985
Expected Return on Plan Assets	**(1,160)**	(1,039)	**(2,320)**	(2,080)
Amortization of Prior Service Cost	**316**	21	**633**	42
Amortization of Net Loss	**3,062**	591	**6,124**	1,182
Net Periodic Pension Cost	**$ 3,018**	$ 1,462	**$ 6,038**	$ 2,923
Postretirement Benefits Other than Pension Plans				
Current Period Service Cost	**$ 334**	$ 316	**$ 669**	$ 633
Interest Cost	**468**	424	**935**	847
Amortization of Net Loss	**141**	62	**282**	316
Amortization of Net Obligation at Transition	**158**	158	**316**	316
Total Postretirement Benefit Cost	**$ 1,101**	$ 960	**$ 2,202**	$ 2,112

Employer Contributions

The funding levels of the pension and postretirement benefit plans are in compliance with standards set by applicable law or regulation. The Company does not have any required minimum funding obligations for its qualified pension plan in 2011. The Company previously disclosed in its financial statements for the year ended December 31, 2010 that it had not determined if any additional discretionary funding would be made in 2011. During the six months ended June 30, 2011, the Company did not make any contributions to its qualified and non-qualified pension plans; discretionary contributions may, however, be made prior to December 31, 2011.

Termination and Amendment of Qualified and Non-Qualified Pension Plans

In July 2010, the Company notified its employees of its plan to terminate its qualified pension plan, with the plan and its related trust to be liquidated following appropriate filings with the Pension Benefit Guaranty Corporation and Internal Revenue Service, effective September 30, 2010. The Company then amended and restated the qualified pension plan to freeze benefit accruals, to provide for termination of the plan, to allow for an early retirement enhancement to be available to all active participants as of September 30, 2010 regardless of their age and years of service as of that date, and to make certain changes that were required or made desirable as a result of developments in the law. Because no further benefits will accrue under the qualified pension plan after September 30, 2010, the Company s related non-qualified pension plan was effectively frozen and no additional benefits will be accrued under those arrangements after September 30, 2010. For further information regarding termination and amendment of qualified and non-qualified pension plans, refer to Note 6 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)

11. STOCK-BASED COMPENSATION

Stock-based compensation expense (including the supplemental employee incentive plan) during the first six months of 2011 and 2010 was $19.3 million and $5.1 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 2011 and 2010 was $11.2 million and $1.9 million, respectively.

Restricted Stock Awards

During the first six months of 2011, 7,300 restricted stock awards were granted with a weighted-average grant date per share value of $43.62. The fair value of restricted stock grants is based on the average of the high and low stock price on the grant date. The Company used an annual forfeiture rate assumption of 7.0% for purposes of recognizing stock-based compensation expense for restricted stock awards.

Restricted Stock Units

During the first six months of 2011, 29,701 restricted stock units were granted to non-employee directors of the Company with a grant date per share value of $41.75. 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 will be issued when the director ceases to be a director of the Company.

Stock Appreciation Rights

During the first six months of 2011, 95,750 stock appreciation rights (SARs) were granted to employees. These awards allow the employee to receive common stock of the Company equal to the intrinsic value over the $40.74 strike price during the contractual term of seven years. The Company calculates the fair value using a Black-Scholes model. 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 Right Granted During the Period	**$ 18.94**
Assumptions:	
Stock Price Volatility	**52.7%**
Risk Free Rate of Return	**2.3%**
Expected Dividend Yield	**0.3%**
Expected Term (in years)	**5.0**

Performance Share Awards

During the first six months of 2011, three types of performance share awards were granted to employees for a total of 394,757 performance shares, which included 92,696 performance share awards based on market conditions and 302,061 performance share awards based on performance conditions measured against the Company s internal performance metrics. Of the 302,061 performance-based awards 92,696 of the shares have a three-year graded performance period. For these shares, 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 vesting date. If the Company does not meet this metric for the applicable period, then the portion of the performance shares that would have been issued on that date will be forfeited. For the remaining 209,365 performance-based awards, 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. Refer to Note 12 of the Notes to the Consolidated Financial Statements in the Form 10-K for further description of the various types of performance share awards.

The performance period for the awards based on internal performance metrics commenced on January 1, 2011 and ends on December 31, 2013 and the grant date per share value for these awards was $40.74, which is based on the average of the high and low stock price on the grant date.

The actual number of shares issued on each anniversary date following the grant date or at the end of the performance period, as applicable, will be determined based on the Company s performance against the performance criteria set by the Company s Compensation Committee. Based on the Company s probability assessment at June 30, 2011, it is considered probable that the criteria for the performance-based awards will be met. The Company used an annual forfeiture rate assumption ranging from 0% to 7% for purposes of recognizing stock-based compensation expense for all performance-based share awards.

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CABOT OIL & GAS CORPORATION

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

The following assumptions were used for the performance shares based on market conditions using a Monte Carlo model to value the liability and equity components of the awards. The equity portion of the 2011 awards was valued on the grant date (February 17, 2011) and was not marked to market. The liability portion of the awards was valued as of June 30, 2011 on a mark-to-market basis.

	Grant Date	June 30, 2011
Value per Share	$ 31.23	$ 16.04 - $48.63
Assumptions:		
Stock Price Volatility	62.0%	37.08% - 47.38%
Risk Free Rate of Return	1.3%	0.10% - 0.63%
Expected Dividend Yield	0.2%	0.2%

12. ASSET RETIREMENT OBLIGATION

The following table provides a rollforward of the asset retirement obligation. Liabilities settled include settlement payments for obligations as well as obligations that were assumed by the purchasers of divested properties. Liabilities incurred include additions to obligations as well as obligations that were assumed by the Company related to acquired properties. Activity related to the Company s asset retirement obligation is as follows:

(In thousands)	
Carrying amount of asset retirement obligations at December 31, 2010	$ 72,311
Liabilities added during the current period	617
Liabilities settled and divested during the current period	(610)
Current period accretion expense	1,730
Carrying amount of asset retirement obligations at June 30, 2011	**$ 74,048**

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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, 2011, and the related condensed consolidated statements of operations for the three month and six month periods ended June 30, 2011 and 2010, and the condensed consolidated statement of cash flows for the six month periods ended June 30, 2011 and 2010. 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, 2010, and the related consolidated statements of operations, stockholders equity, comprehensive income and of cash flows for the year then ended (not presented herein), and in our report dated February 28, 2011, 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, 2010, 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 29, 2011

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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, 2011 and 2010 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 Corporation Annual Report on Form 10-K for the year ended December 31, 2010 (Form 10-K).

As a result of our production growth and the commencement of various transportation and gathering agreements in 2011, we began separately reporting our transportation and gathering costs as a component of operating expenses in the Condensed Consolidated Statement of Operations. Previously reported transportation and gathering costs were reflected as a component of Natural Gas Revenues and have been reclassified to conform to current year presentation. Accordingly, previously reported operating revenues and operating expenses have increased with no impact on previously reported net income.

Overview

On an equivalent basis, our production for the six months ended June 30, 2011 increased by 45% compared to the six months ended June 30, 2010. For the six months ended June 30, 2011, we produced 82.7 Bcfe compared to 57.1 Bcfe for the six months ended June 30, 2010. Natural gas production was 79.5 Bcf and crude oil/condensate/NGL production was 529 Mbbls for the first half of 2011. Natural gas production increased by 46% when compared to the first half of 2010, which had production of 54.4 Bcf. This increase was primarily a result of increased production in the North region associated with the drilling program and upgrades to the Lathrop compressor station, which included the commissioning of new compression during the first six months of 2011 in Susquehanna County, Pennsylvania. Partially offsetting the production increase in the North region were decreases in production in the South region due to normal production declines and a shift from gas to oil projects. Crude oil/condensate/NGL production increased by 14%, to 529 Mbbls, when compared to the first half of 2010, which had production of 465 Mbbls. This increase was primarily the result of increased production in the South region associated with the drilling program in the Eagle Ford Shale in South Texas, partially offset by a slight decrease in production in the North.

Our average realized natural gas price for the first half of 2011 was $4.67 per Mcf, 24% lower than the $6.15 per Mcf price realized in the first half of 2010. Our average realized crude oil price for the first half of 2011 was $91.80 per Bbl, 5% lower than the $97.04 per Bbl price realized in the first half of 2010. 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, 2011 increased by $33.1 million, or 8%, from the six months ended June 30, 2010. Natural gas revenues, excluding unrealized gains/losses from the change in fair value of our basis swaps, increased by $37.3 million, or 11%, for the six months ended June 30, 2011 as compared to the six months ended June 30, 2010 as the increase in natural gas production more than offset the lower realized natural gas prices. Crude oil and condensate revenues increased by $5.4 million, or 13%, for the first six months of 2011 as compared to the first six months of 2010, due to increased crude oil production partially offset by lower realized crude oil prices. Brokered natural gas revenues decreased by $8.7 million, or 23%, due to a decreased sales price and decreased 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 2011, we expect to spend approximately $600 million in capital and exploration expenditures, net of proceeds from the sale of assets that may be used to fund incremental capital and exploration expenditures. We believe our cash on hand, operating cash flow in 2011, proceeds from asset sales and borrowings from our credit facility will be sufficient to fund our remaining budgeted capital and exploration spending in 2011. 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, 2011, we invested approximately $397.4 million in our exploration and development efforts.

During the first six months of 2011, we drilled 52 gross wells (45 development, four exploratory and three extension wells) with a success rate of 100% compared to 45 gross wells (41 development, two exploratory and two extension wells) with a success rate of 98% for the comparable period of the prior year. For the full year of 2011, we plan to drill approximately 150 gross (98.7 net) wells.

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While we consider acquisitions from time to time, 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.

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, 2011 were funds generated from the sale of natural gas and crude oil production (including hedge realizations), borrowings under our credit facility and the sales of properties and other assets. These cash flows were primarily used to fund our development and exploration expenditures, in addition to payment of dividends and repayment of debt. 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. 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 revenues.

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 availability under our credit facility and liquidity available to meet our working capital requirements.

	Six Months Ended June 30,	
(In thousands)	**2011**	**2010**
Cash Flows Provided by Operating Activities	**$ 220,701**	$ 243,178
Cash Flows Used in Investing Activities	**(349,878)**	(437,401)
Cash Flows Provided by Financing Activities	**112,542**	201,750
Net (Decrease) / Increase in Cash and Cash Equivalents	**$ (16,635)**	$ 7,527

***Operating Activities*.** Key components impacting net operating cash flows are commodity prices, production volumes and operating expenses. Net cash provided by operating activities in the first six months of 2011 decreased by $22.5 million over the first six months of 2010. This decrease was primarily due to changes in working capital partially offset by increased operating income in 2011 as a result of higher operating revenues and an increase in the gain on sale of assets that outpaced the increase in operating expenses. The increase in operating revenues was primarily due to an increase in equivalent production partially offset by lower realized natural gas and crude oil prices. Equivalent production volumes increased by 45% for the six months ended June 30, 2011 compared to the six months ended June 30, 2010 as a result of higher natural gas and crude oil production. Average realized natural gas prices decreased by 24% for the first six months of 2011 compared to the first six months of 2010. Average realized crude oil prices decreased by 5% compared to the same period. See Results of Operations for additional information relative to commodity price, production and operating expense 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.

***Investing Activities*.** The primary use of cash in investing activities was capital spending. We established our 2011 capital budget 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. Cash flows used in investing activities decreased by $87.5 million for the first six months of 2011 compared to the first six months of 2010. The decrease was primarily due to a decrease of $49.9 million in capital and exploration expenditures and higher proceeds from sale of assets of $37.6 million.

***Financing Activities*.** Cash flows provided by financing activities decreased by $89.2 million from the first six months of 2010 to the first six months of 2011. This was primarily due to an increase in repayments of debt partially offset by higher borrowings in the first six months of 2011 compared to the first six months of 2010.

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At June 30, 2011, we had $333.0 million of borrowings outstanding under our unsecured credit facility at a weighted-average interest rate of 4.3%. The credit facility provides for an available credit line of $900 million and contains an accordion feature allowing us to increase the available credit line to $1.0 billion, if any one or more of the existing banks or new banks agree to provide such increased commitment amount. Effective April 1, 2011, the lenders under our credit facility approved an increase in the borrowing base under the facility from $1.5 billion to $1.7 billion as part of the annual redetermination under the terms of the credit facility. As of June 30, 2011, our available credit under our credit facility was $566.8 million.

We are in compliance in all material respects with our debt covenants as of June 30, 2011.

We strive to manage our debt at a level below the available credit line in order to maintain borrowing capacity. Our revolving credit facility includes a covenant limiting our total debt. Management believes that, with operating cash flow, existing cash on hand, availability under our revolving credit facility and proceeds from the sale of assets, we have the capacity to finance our spending plans, service our debt obligations as they become due and maintain our strong financial position.

Capitalization

Information about our capitalization is as follows:

(Dollars in millions)	June 30, 2011	December 31, 2010
Debt [1]	**$ 1,095.0**	$ 975.0
Stockholders Equity	**1,966.2**	1,872.7
Total Capitalization	**$ 3,061.2**	$ 2,847.7
Debt to Capitalization	**35.8%**	34.2%
Cash and Cash Equivalents	**$ 39.3**	$ 55.9

(1) *Includes $333.0 million and $213.0 million of borrowings outstanding under our revolving credit facility at June 30, 2011 and December 31, 2010, respectively.*

During the six months ended June 30, 2011, we paid dividends of $6.3 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, borrowings under 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:

	Six Months Ended June 30,	
(In millions)	2011	2010
Capital Expenditures		
Drilling and Facilities	**$ 345.8**	$ 261.6
Leasehold Acquisitions	**30.0**	90.3

Acquisitions		0.8
Pipeline and Gathering	**5.7**	18.1
Other	**5.0**	4.5
	386.5	375.3
Exploration Expense	**10.9**	18.7
Total	**$ 397.4**	$ 394.0

For the full year of 2011, we plan to drill approximately 150 gross (98.7 net) wells. This 2011 drilling program includes approximately $600 million in total capital and exploration expenditures, net of proceeds from the sale of assets that may be used to fund incremental capital and exploration expenditures. See Overview 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

We have various contractual obligations in the normal course of our operations. For further information, please refer to Transportation Agreements under Note 6 in the Notes to the Condensed Consolidated Financial Statements and Note 8 in the Notes to Consolidated Financial Statements included in our 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 Issued Accounting Pronouncements

In May 2011, the Financial Accounting Standards Board (FASB) issued Accounting Standards Update (ASU) No. 2011-04, Amendments to Achieve Common Fair Value Measurement and Disclosure Requirements in U.S. GAAP and IFRSs. The amendments in ASU No. 2011-04 generally represent clarifications of Topic 820, but also include some instances where a particular principle or requirement for measuring fair value or disclosing information about fair value measurements has changed. ASU No. 2011-04 results in common principles and requirements for measuring fair value and for disclosing information about fair value measurements in accordance with U.S. GAAP and IFRSs. The amendments in ASU No. 2011-04 are to be applied prospectively. For public entities, the amendments are effective for interim and annual periods beginning after December 15, 2011. Early application by public entities is not permitted. We do not expect this guidance to have a significant impact on our consolidated financial position, results of operations or cash flows.

In June 2011, the FASB issued ASU No. 2011-05, Presentation of Comprehensive Income, requiring most entities to present items of net income and other comprehensive income either in one continuous statement referred to as the statement of comprehensive income or in two separate, but consecutive, statements of net income and other comprehensive income. The new requirements are effective for public entities for fiscal years (including interim periods) beginning after December 15, 2011. We do not expect this guidance to have a significant impact on our consolidated financial position, results of operations or cash flows.

Results of Operations

Second Quarter of 2011 and 2010 Compared

We reported net income in the second quarter of 2011 of $54.7 million, or $0.53 per share, compared to net income in the second quarter of 2010 of $21.7 million, or $0.21 per share. Net income increased in the second quarter of 2011 by $33.0 million, primarily due to an increase in operating revenues and gain on sale of assets partially offset by increases in operating expenses, interest expense and income tax expense.

Operating revenues increased by $40.5 million due to increased natural gas and crude oil and condensate revenues partially offset by decreased brokered natural gas revenues. Operating expenses increased by $15.6 million between periods primarily due to increases in general and administrative expenses, transportation and gathering expenses and depreciation, depletion, and amortization, partially offset by lower taxes other than income, exploration expense, brokered natural gas cost and direct operating expenses. In addition, net income was impacted during the second quarter by increased gain on sale of assets, partially offset by higher income tax and interest expense.

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Revenue, Price and Volume Variances

Below is a discussion of revenue, price and volume variances.

Revenue Variances (In thousands)	Three Months Ended June 30, 2011	2010	Variance Amount	Percent
Natural Gas [1]	**$ 201,260**	$ 163,586	$ 37,674	23%
Brokered Natural Gas	**11,072**	13,348	(2,276)	(17%)
Crude Oil and Condensate	**28,042**	21,211	6,831	32%
Other	**1,225**	1,154	71	6%

[1] *Natural Gas Revenues exclude the unrealized loss of $0.9 and the unrealized gain of $0.9 million from the change in fair value of our basis swaps in 2011 and 2010, respectively.*

	Three Months Ended June 30, 2011	2010	Variance Amount	Percent	Increase (Decrease) (In thousands)
Price Variances					
Natural Gas [1]	**$ 4.67**	$ 5.65	$ (0.98)	(17%)	$ (42,414)
Crude Oil and Condensate [2]	**$ 95.17**	$ 96.70	$ (1.53)	(2%)	(451)
Total					$ (42,865)
Volume Variances					
Natural Gas (Mmcf)	**43,128**	28,961	14,167	49%	$ 80,088
Crude Oil and Condensate (Mbbl)	**295**	219	76	35%	7,282
Total					$ 87,370

[1] *These prices include the realized impact of derivative instrument settlements, which increased the price by $0.32 per Mcf in 2011 and by $1.44 per Mcf in 2010.*

[2] *These prices include the realized impact of derivative instrument settlements, which decreased the price by $1.74 per Bbl in 2011 and increased the price by $21.82 per Bbl in 2010.*

Natural Gas Revenues

The increase in natural gas revenues of $37.7 million, excluding the impact of unrealized gains and losses discussed above, is primarily due to increased production during the second quarter of 2011 in Susquehanna County, Pennsylvania, partially offset by lower realized natural gas prices. The increased production is primarily due to increased production in the North region associated with the drilling program and the start up of additional compressors at the Lathrop compressor station in Susquehanna County, partially offset by decreases in production in the South region due to normal production declines and a shift from gas to oil projects.

Crude Oil and Condensate Revenues

The increase in crude oil and condensate revenues of $6.8 million is primarily due to increased production in the South region associated with the drilling program in the Eagle Ford Shale in South Texas, partially offset by lower realized oil prices.

Brokered Natural Gas Revenue and Cost

	Three Months Ended June 30,		Variances		Price and Volume
	2011	2010	Amount	Percent	Variance (In thousands)
Brokered Natural Gas Sales					
Sales Price ($/Mcf)	**$ 5.10**	$ 5.04	$ 0.06	1%	$ 130
Volume Brokered (Mmcf)	**x 2,173**	x 2,649	(476)	-18%	(2,406)
Brokered Natural Gas Revenues *(In thousands)*	**$ 11,072**	$ 13,348			$ (2,276)
Brokered Natural Gas Purchases					
Purchase Price *($/Mcf)*	**$ 4.51**	$ 4.45	$ 0.06	1%	$ (126)
Volume Brokered *(Mmcf)*	**x 2,173**	x 2,649	(476)	-18%	2,123
Brokered Natural Gas Cost *(In thousands)*	**$ 9,796**	$ 11,793			$ 1,997
Brokered Natural Gas Margin *(In thousands)*	**$ 1,276**	$ 1,555			$ (279)

The decreased brokered natural gas margin of $0.3 million is a result of primarily a decrease in brokered volumes.

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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,			
	2011		2010	
(In thousands)	Realized	Unrealized	Realized	Unrealized
Operating Revenues Increase / (Decrease) to Revenue				
Cash Flow Hedges				
Natural Gas	**$ 13,667**	**$**	$ 41,812	$
Crude Oil	**(514)**		4,779	
Total Cash Flow Hedges	**13,153**		46,591	
Other Derivative Financial Instruments				
Natural Gas Basis Swaps		**(903)**		942
Total Other Derivative Financial Instruments		**(903)**		942
Total Cash Flow Hedges and Other Derivative Financial Instruments	**$ 13,153**	**$ (903)**	$ 46,591	$ 942

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, Goldman Sachs and Bank of America.

Operating and Other Expenses

	Three Months Ended June 30,		Variance	
(In thousands)	2011	2010	Amount	Percent
Operating and Other Expenses				
Brokered Natural Gas Cost	**$ 9,796**	$ 11,793	$ (1,997)	(17%)
Direct Operations	**22,579**	24,347	(1,768)	(7%)
Transportation and Gathering	**16,074**	4,767	11,307	237%
Taxes Other Than Income	**5,877**	11,841	(5,964)	(50%)
Exploration	**4,592**	10,233	(5,641)	(55%)
Depreciation, Depletion and Amortization	**83,225**	76,726	6,499	8%
General and Administrative	**26,006**	12,853	13,153	102%
Total Operating Expense	**$ 168,149**	$ 152,560	$ 15,589	10%
Gain / (Loss) on Sale of Assets	**$ 34,071**	$ 4,387	$ 29,684	677%
Interest Expense and Other	**18,044**	15,769	2,275	14%
Income Tax Expense	**33,897**	14,617	19,280	132%

Total costs and expenses from operations increased by $15.6 million, or 10%, in the second quarter of 2011 compared to the same period of 2010. The primary reasons for this fluctuation are as follows:

General and Administrative increased by $13.2 million primarily due to $9.3 million higher stock-based compensation expense primarily associated with the mark to market of the liability portion of our performance shares as a result of our higher stock price of $66.31 as of June 30, 2011 compared to $31.22 as of June 30, 2010. Higher incentive compensation expense and professional service costs also contributed to the increase.

Transportation and Gathering increased by $11.3 million primarily due to the commencement of various firm transportation and gathering arrangements in the first half of 2011 in the North region.

Depreciation, Depletion and Amortization increased by $6.5 million, of which $6.6 million was due to increased depreciation and depletion from increased capital spending and higher equivalent production volumes offset by a lower DD&A rate of $1.63 per Mcfe for three months ended June 30, 2011 compared to $2.21 per Mcfe for three months ended June 30, 2010. The increase in depletion and depreciation was offset by a decrease in amortization of unproved properties of $0.1 million.

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Taxes Other Than Income decreased $6.0 million primarily due to lower production taxes due to tax credits and related refunds received in 2011 on qualifying wells and lower ad valorem tax expense partially offset by higher franchise taxes expense.

Exploration Expense decreased $5.6 million primarily due to lower geophysical and geological costs in the North region primarily due to a reduction in activity.

Brokered Natural Gas Costs decreased $2.0 million. See the preceding table titled *Brokered Natural Gas Revenue and Cost* for further analysis.

Direct Operations decreased $1.8 million largely due to lower compressor expenses in both the North and South regions primarily due to the sale of our gathering system in the North region in the fourth quarter of 2010, increased use of centralized compression and a shift in our drilling program, and decreased lease maintenance expense in both the North and South regions. Partially offsetting these decreases were increases in operating costs primarily driven by increased production. Higher workover and contract labor expense and increased plugging and abandonment expense as the result of increased regulatory requirements also contributed to higher operating costs.

Gain / (Loss) on Sale of Assets

An aggregate gain of $34.1 million was recognized in the second quarter of 2011 primarily due to the sale of oil and gas properties in East Texas. 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.

Income Tax Expense

Income tax expense increased by $19.3 million in the second quarter of 2011 compared to the second quarter of 2010 primarily due to increased pretax income partially offset by a lower effective tax rate. The effective tax rate for the second quarter of 2011 and 2010 was 38.3% and 40.3%, respectively.

Interest Expense and Other

Interest expense and other increased by $2.3 million in the second quarter of 2011 compared to the second quarter of 2010 primarily due to an increase in weighted-average borrowings under our credit facility based on daily balances of approximately $342.0 million during the second quarter of 2011 compared to approximately $317.4 million during the second quarter of 2010. In addition, the weighted-average effective interest rate on the credit facility increased to approximately 3.8% during the second quarter of 2011 compared to approximately 3.68% during the second quarter of 2010. Furthermore, in December 2010 we also issued $175 million aggregate principal amount of 5.58% weighted-average fixed rate notes, which increased interest expense recognized in the second quarter of 2011.

Six Months of 2011 and 2010 Compared

We reported net income in the first six months of 2011 of $67.5 million, or $0.65 per share, compared to net income in the first six months of 2010 of $50.4 million, or $0.49 per share. Net income increased in the first six months of 2011 by $17.2 million, primarily due to an increase in operating revenues and gain on sale of assets, partially offset by increases in operating expenses, interest expense and income tax expense.

Operating revenues increased by $33.1 million, largely due to increased natural gas, crude oil and condensate and other revenues, partially offset by decreased brokered natural gas revenues. Operating expenses increased by $30.2 million between periods primarily due to increases in general and administrative expenses, transportation and gathering expenses, depreciation, depletion and amortization and direct operations partially offset by lower taxes other than income, brokered natural gas cost and exploration expense. In addition, net income was impacted during the first six months by increased gain on sale of assets partially offset by higher interest expense and income tax expense.

Revenue, Price and Volume Variances

Below is a discussion of revenue, price and volume variances.

Revenue Variances (In thousands)	Six Months Ended June 30, 2011	2010	Variance Amount	Percent
Natural Gas [1]	**$ 371,341**	$ 334,044	$ 37,297	11%
Brokered Natural Gas	**29,480**	38,221	(8,741)	(23%)
Crude Oil and Condensate	**46,634**	41,193	5,441	13%
Other	**3,153**	2,774	379	14%

(1) *Natural Gas Revenues exclude the unrealized loss of $0.9 million and the unrealized gain of $0.4 million from the change in fair value of our basis swaps in 2011 and 2010, respectively.*

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	Six Months Ended June 30, 2011	Six Months Ended June 30, 2010	Variance Amount	Variance Percent	Increase (Decrease) (In thousands)
Price Variances					
Natural Gas [(1)]	**$ 4.67**	$ 6.15	$ (1.48)	(24%)	$ (117,578)
Crude Oil and Condensate [(2)]	**$ 91.80**	$ 97.04	$ (5.24)	(5%)	(2,661)
Total					$ (120,239)
Volume Variances					
Natural Gas (Mmcf)	**79,499**	54,353	25,146	46%	$ 154,875
Crude Oil and Condensate (Mbbl)	**508**	425	83	20%	8,102
Total					$ 162,977

(1) These prices include the realized impact of derivative instrument settlements, which increased the price by $0.34 per Mcf in 2011 and by $1.29 per Mcf in 2010.

(2) These prices include the realized impact of derivative instrument settlements, which decreased the price by $1.61 per Bbl in 2011 and increased the price by $22.08 per Bbl in 2010.

Natural Gas Revenues

The increase in Natural Gas Revenues of $37.3 million is primarily due to increased production during the first half of 2011, partially offset by lower realized natural gas prices. The increased production is primarily due to increased production in the North region associated with the drilling program and the start up of additional compressors at the Lathrop compressor station during the first half of the year in Susquehanna County, partially offset by decreases in production in the South region due to normal production declines and a shift from gas to oil projects.

Crude Oil and Condensate Revenues

The increase in Crude Oil and Condensate Revenues of $5.4 million is primarily due to increased production in the South region associated with the drilling program in the Eagle Ford Shale in South Texas, partially offset by lower realized oil prices.

Brokered Natural Gas Revenue and Cost

	Six Months Ended June 30, 2011	Six Months Ended June 30, 2010	Variance Amount	Variance Percent	Price and Volume Variances (In thousands)
Brokered Natural Gas Sales					
Sales Price ($/Mcf)	**$ 5.21**	$ 5.75	$ (0.54)	(9%)	$ (3,073)
Volume Brokered (Mmcf)	**x 5,661**	x 6,644	(983)	(15%)	(5,668)
Brokered Natural Gas Revenues (In thousands)	**$ 29,480**	$ 38,221			$ (8,741)
Brokered Natural Gas Purchases					
Purchase Price ($/Mcf)	**$ 4.44**	$ 4.98	$ (0.54)	(11%)	$ 3,021
Volume Brokered (Mmcf)	**x 5,661**	x 6,644	(983)	(15%)	4,882
Brokered Natural Gas Cost (In thousands)	**$ 25,158**	$ 33,061			$ 7,903
Brokered Natural Gas Margin (In thousands)	**$ 4,322**	$ 5,160			$ (838)

The decreased brokered natural gas margin of $0.8 million is primarily a result of a decrease in brokered volumes coupled with a decrease in purchase price that outpaced the sales price.

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:

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	Six Months Ended June 30,			
	2011		2010	
(In thousands)	Realized	Unrealized	Realized	Unrealized
Operating Revenues Increase / (Decrease) to Revenue				
Cash Flow Hedges				
Natural Gas	**$ 27,148**	**$**	$ 70,253	$
Crude Oil	**(816)**		9,362	
Total Cash Flow Hedges	**26,332**		79,615	
Other Derivative Financial Instruments				
Natural Gas Basis Swaps		**(886)**		355
Total Other Derivative Financial Instruments		**(886)**		355
Total Cash Flow Hedges and Other Derivative Financial Instruments	**$ 26,332**	**$ (886)**	$ 79,615	$ 355

Operating and Other Expenses

	Six Months Ended June 30,		Variance	
(In thousands)	2011	2010	Amount	Percent
Operating and Other Expenses				
Brokered Natural Gas Cost	**$ 25,158**	$ 33,061	$ (7,903)	(24%)
Direct Operations	**49,586**	47,330	2,256	5%
Transportation and Gathering	**28,942**	8,557	20,385	238%
Taxes Other Than Income	**14,028**	22,646	(8,618)	(38%)
Exploration	**10,900**	18,659	(7,759)	(42%)
Depreciation, Depletion and Amortization	**160,349**	150,224	10,125	7%
General and Administrative	**50,305**	28,599	21,706	76%
Total Operating Expense	**$ 339,268**	$ 309,076	$ 30,192	10%
Gain / (Loss) on Sale of Assets	**$ 32,554**	$ 5,146	$ 27,408	533%
Interest Expense and Other	**35,411**	30,681	4,730	15%
Income Tax Expense	**40,034**	31,598	8,436	27%

Total costs and expenses from operations increased by $30.2 million, or 10%, in the first six months of 2011 compared to the same period of 2010. The primary reasons for this fluctuation are as follows:

General and Administrative increased by $21.7 million primarily due to $14.2 million higher stock-based compensation expense primarily associated with the mark to market of the liability portion of our performance shares as a result of our higher stock price of $66.31 as of June 30, 2011 compared to $31.22 as of June 30, 2010. Higher incentive compensation expense and professional service costs also contributed to the increase.

Transportation and Gathering increased by $20.4 million primarily due to the commencement of various firm transportation and gathering arrangements in the first half of 2011 primarily in the North region.

Depreciation, Depletion and Amortization increased by $10.1 million, of which $16.4 million was due to increased depreciation and depletion from increased capital spending and higher equivalent production volumes offset by a lower DD&A rate of $1.70 per Mcfe for six months ended June 30,2011 compared to $2.19 per Mcfe for six months ended June 30, 2010. The increase in depletion and depreciation was offset by a decrease in amortization of unproved properties of $6.2 million primarily due to a decrease in amortization rates due to a shift in our drilling and development activities.

Taxes Other Than Income decreased $8.6 million due to decreased production taxes due to tax refunds and credits received in 2011 on qualifying wells and lower ad valorem taxes partially offset by an increase in franchise taxes expense.

Brokered Natural Gas Costs decreased $7.9 million. See the preceding table titled *Brokered Natural Gas Revenue and Cost* for further analysis.

Exploration Expense decreased $7.8 million primarily due to lower geophysical and geological costs in the North region primarily due to a reduction in activity.

Direct Operations increased $2.3 million largely due to increased operating costs primarily driven by increased production. Contributing to the increase are higher workover and environmental and regulatory costs in both the North and South regions and higher plugging and abandonment expense. Plugging and abandonment expense has increased in the South region due to increased plugging and abandonment activity as a result of an increase in regulatory requirements. Offsetting these increases were lower compression expenses in both the North and South regions primarily due to the sale of our gathering system in the North region in the fourth quarter of 2010, increased use of centralized compression and a shift in our drilling program.

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Gain / (Loss) on Sale of Assets

An aggregate gain of $32.6 million was recognized in the first half of 2011 on the sale of oil and gas properties in the East Texas and the sale of non-core assets as part of our ongoing asset portfolio management program. In 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 charges of $5.8 million on assets held for sales.

Income Tax Expense

Income tax expense increased by $8.4 million in the first six months of 2011 compared to the first six months of 2010 primarily due to increased pretax income partially offset by a lower effective tax rate. The effective tax rate for the first six months of 2011 and 2010 was 37.2% and 38.5%, respectively. The effective tax rate was lower due to a reduction in estimated state tax liabilities.

Interest Expense and Other

Interest expense and other increased by $4.7 million in the first six months of 2011 compared to the first six months of 2010 primarily due to an increase in weighted-average borrowings under our credit facility based on daily balances of approximately $305.9 million during the first six months of 2011 compared to approximately $259.0 million during the first six months of 2010. The weighted-average effective interest rate on the credit facility increased to approximately 4.3% during the first six months of 2011 compared to approximately 3.7% during the first six months of 2010. In addition, in December 2010, we also issued $175 million aggregate principal amount of 5.58% weighted-average fixed rate notes, which increased interest expense recognized in the first six months of 2011.

Forward-Looking Information

The statements regarding future financial and operating performance and results, market prices, future hedging activities and other statements that are not historical facts contained in this report are forward-looking statements. The words expect, project, estimate, believe, anticipate, intend, budget, plan, forecast, predict, may, should, could, will and similar expressions are also intended to identify forward-lool 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.

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, 2011, we had 42 derivative contracts open: 27 natural gas price swap arrangements, five natural gas collar arrangements, six natural gas basis swaps, one crude oil price collar arrangement and three crude oil price swap arrangements. During the first six months of 2011, we entered into 31 new derivative contracts covering anticipated crude oil and natural gas production for 2011, 2012, and 2013.

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As of June 30, 2011, 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 Swaps	$6.24	per Mcf	6,508	Mmcf	Jul. 2011 - Dec. 2011	$9,372
Natural Gas Swaps	$5.18	per Mcf	118,049	Mmcf	Jul. 2011 - Dec. 2012	32,008
Natural Gas Swaps	$5.28	per Mcf	17,854	Mmcf	Jan. 2012 - Dec. 2012	4,342
Natural Gas Collars	$6.17 Ceiling / $5.13 Floor	per Mcf	17,805	Mmcf	Jan. 2013 - Dec. 2013	3,456
Crude Oil Collars	$93.25 Ceiling / $80.00 Floor	per Bbl	184	Mbbl	Jul. 2011 - Dec. 2011	(1,167)
Crude Oil Swaps	$106.20	per Bbl	184	Mbbl	Jul. 2011 - Dec. 2011	1,710
Crude Oil Swaps	$105.00	per Bbl	366	Mbbl	Jan. 2012 - Dec. 2012	1,807
						$51,528
Derivatives Not Designated as Hedging Instruments						
Natural Gas Basis Swaps	$(0.27)	per Mcf	16,123	Mmcf	Jan. 2012 - Dec. 2012	(3,057)
						$48,471

The amounts set forth under the net unrealized gain/(loss) column in the table above represent our total unrealized gain position at June 30, 2011 and excludes the impact of non-performance risk of $0.1 million. Non-performance risk was primarily evaluated by reviewing credit default swap spreads for the various financial institutions in which we have derivative transactions, while non-performance risk of the Company is evaluated using a market credit spread provided by the Company s bank.

From time to time, we enter into natural gas and crude oil swap and collar agreements with counterparties to hedge price risk associated with a portion of our production. These agreements are not held for trading purposes. Under the 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. Under the collar agreements, if the index price rises above the ceiling price, we pay the counterparty. If the index price falls below the floor price, the counterparty pays us.

We had natural gas price swaps covering 28.9 Bcf, or 36%, of our first six months of 2011 natural gas production at an average price of $5.39 per Mcf.

We had one crude oil swap covering 91 Mbbl, or 18%, of our first six months of 2011 crude oil production, at an average price of $106.20 per Bbl.

During the first six months of 2011, crude oil collars covered 181 Mbbl, or 36% of total crude oil production, with a weighted-average floor price of $80.00 per Bbl and a weighted-average ceiling price of $93.25 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 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 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, 2011		December 31, 2010	
(In thousands)	Carrying Amount	Estimated Fair Value	Carrying Amount	Estimated Fair Value
Long-Term Debt	**$ 1,095,000**	**$ 1,231,089**	$ 975,000	$ 1,100,830

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 2011 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.

We have received a number of Notices of Violation from the Pennsylvania Department of Environmental Protection (PaDEP) relating to alleged violations, primarily with respect to the Pennsylvania Clean Streams Law, the Pennsylvania Oil and Gas Act and the Pennsylvania Solid Waste Management Act and the rules and regulations promulgated thereunder. We have responded to these Notices of Violation, have remediated the areas in question and are actively cooperating with the PaDEP. While we cannot predict with certainty whether these Notices of Violation will result in fines and/or penalties, if fines and/or penalties are imposed, the aggregate of these fines and/or penalties could result in monetary sanctions in excess of $100,000.

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, 2010.

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 six months ended June 30, 2011, 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, 2011 was 4,795,300.

ITEM 5. Other Information

Effective January 1, 2011, the Company amended and restated the Deferred Compensation Plan to incorporate prior plan amendments and to provide for Company contributions that may not be made to the Company s tax-qualified Savings Investment Plan as a result of limitations imposed by the Internal Revenue Code.

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ITEM 6. Exhibits

Exhibit Number	Description
*10.1	Deferred Compensation Plan of the Company, as Amended and Restated, Effective January 1, 2011
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.DEF	XBRL Taxonomy Extension Definition Linkbase Document
101.LAB	XBRL Taxonomy Extension Label Linkbase Document
101.PRE	XBRL Taxonomy Extension Presentation Linkbase Document

* Compensatory plan, contract or agreement.

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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 29, 2011	By: /s/ DAN O. DINGES **Dan O. Dinges** **Chairman, President and** **Chief Executive Officer** **(Principal Executive Officer)**
July 29, 2011	By: /s/ SCOTT C. SCHROEDER **Scott C. Schroeder** **Vice President, Chief Financial Officer and Treasurer** **(Principal Financial Officer)**
July 29, 2011	By: /s/ TODD M. ROEMER **Todd M. Roemer** **Controller** **(Principal Accounting Officer)**

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