CABOT OIL & GAS CORP
Form 10-Q
April 30, 2009
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UNITED STATES

SECURITIES AND EXCHANGE COMMISSION

WASHINGTON, D.C. 20549

FORM 10-Q

x QUARTERLY REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934.
For the quarterly period ended March 31, 2009

¨ TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934.
Commission file number 1-10447

CABOT OIL & GAS CORPORATION

(Exact name of registrant as specified in its charter)

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

1200 Enclave Parkway, Houston, Texas 77077

(Address of principal executive offices including ZIP Code)

(281) 589-4600

(Registrant s telephone number, including area code)

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months and (2) has been subject to such filing requirements for the past 90 days.

Yes x No ¨

Indicate by check mark whether the registrant has submitted electronically and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T (§232.405 of this chapter) during the preceding 12 months (or

for such shorter period that the registrant was required to submit and post such files).

Yes ¨ No ¨

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

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

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Exchange Act).

Yes ¨ No **x**

As of April 27, 2009, there were 103,637,883 shares of Common Stock, Par Value $.10 Per Share, outstanding.

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PART I. FINANCIAL INFORMATION

ITEM 1. Financial Statements

CABOT OIL & GAS CORPORATION

CONDENSED CONSOLIDATED STATEMENT OF OPERATIONS (Unaudited)

(In thousands, except per share amounts)	Three Months Ended March 31, 2009	2008
OPERATING REVENUES		
Natural Gas Production	**$ 184,522**	$ 166,559
Brokered Natural Gas	**33,381**	35,620
Crude Oil and Condensate	**14,242**	16,487
Other	**1,794**	985
	233,939	219,651
OPERATING EXPENSES		
Brokered Natural Gas Cost	**29,749**	30,290
Direct Operations Field and Pipeline	**25,479**	17,491
Exploration	**6,466**	5,061
Depreciation, Depletion and Amortization	**55,785**	41,516
Impairment of Unproved Properties	**9,307**	4,751
General and Administrative	**17,065**	27,573
Taxes Other Than Income	**12,898**	16,897
	156,749	143,579
Gain on Sale of Assets	**12,707**	
INCOME FROM OPERATIONS	**89,897**	76,072
Interest Expense and Other	**14,226**	5,991
Income Before Income Taxes	**75,671**	70,081
Income Tax Expense	**28,091**	24,106
NET INCOME	**$ 47,580**	$ 45,975
Basic Earnings Per Share	**$ 0.46**	$ 0.47
Diluted Earnings Per Share	**$ 0.46**	$ 0.46
Weighted-Average Common Shares Outstanding	**103,521**	97,716
Diluted Common Shares (Note 5)	**104,111**	98,925

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)	March 31, 2009	December 31, 2008
ASSETS		
Current Assets		
Cash and Cash Equivalents	**$ 25,249**	$ 28,101
Accounts Receivable, Net (Note 3)	**75,218**	109,613
Inventories (Note 3)	**27,618**	45,677
Current Derivative Contracts (Note 7)	**318,690**	264,660
Other Current Assets (Note 3)	**10,299**	12,500
Total Current Assets	**457,074**	460,551
Properties and Equipment, Net (Successful Efforts Method) (Note 2)	**3,191,105**	3,135,828
Long-Term Derivative Contracts (Note 7)	**86,496**	90,542
Other Assets (Note 3)	**14,096**	14,743
	$ 3,748,771	$ 3,701,664
LIABILITIES AND STOCKHOLDERS EQUITY		
Current Liabilities		
Accounts Payable (Note 3)	**$ 142,953**	$ 222,985
Current Portion of Long-Term Debt	**36,714**	35,857
Deferred Income Taxes	**84,648**	63,985
Income Taxes Payable	**7,774**	5,535
Accrued Liabilities (Note 3)	**40,225**	50,551
Total Current Liabilities	**312,314**	378,913
Long-Term Liability for Pension and Postretirement Benefits (Note 9)	**56,529**	54,714
Long-Term Debt (Note 4)	**840,286**	831,143
Deferred Income Taxes	**623,340**	599,106
Other Liabilities (Note 3)	**47,408**	47,226
Total Liabilities	**1,879,877**	1,911,102
Commitments and Contingencies (Note 6)		
Stockholders Equity		
Common Stock:		
Authorized 120,000,000 Shares of $0.10 Par Value Issued 103,840,083 Shares and 103,561,268 Shares in 2009 and 2008, respectively	**10,384**	10,356
Additional Paid-in Capital	**679,137**	675,568
Retained Earnings	**966,038**	921,561
Accumulated Other Comprehensive Income (Note 8)	**216,684**	186,426
Less Treasury Stock, at Cost:		
202,200 Shares in 2009 and 2008, respectively	**(3,349)**	(3,349)
Total Stockholders Equity	**1,868,894**	1,790,562
	$ 3,748,771	$ 3,701,664

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)	Three Months Ended March 31, 2009	2008
CASH FLOWS FROM OPERATING ACTIVITIES		
Net Income	**$ 47,580**	$ 45,975
Adjustments to Reconcile Net Income to Cash Provided by Operating Activities:		
Depreciation, Depletion and Amortization	**55,785**	41,516
Impairment of Unproved Properties	**9,307**	4,751
Deferred Income Tax Expense	**26,349**	23,560
Gain on Sale of Assets	**(12,707)**	
Exploration Expense	**6,466**	5,061
Unrealized Gain on Derivatives	**(941)**	
Stock-Based Compensation Expense and Other	**6,200**	17,539
Changes in Assets and Liabilities:		
Accounts Receivable, Net	**34,395**	(25,719)
Inventories	**18,059**	14,849
Other Current Assets	**2,201**	859
Other Assets	**(2)**	(534)
Accounts Payable and Accrued Liabilities	**(45,489)**	2,981
Income Taxes Payable	**2,238**	4,577
Other Liabilities	**3,093**	1,931
Stock-Based Compensation Tax Benefit		(4,642)
Net Cash Provided by Operating Activities	**152,534**	132,704
CASH FLOWS FROM INVESTING ACTIVITIES		
Capital Expenditures	**(171,029)**	(128,101)
Proceeds from Sale of Assets	**15,063**	
Exploration Expense	**(6,466)**	(5,061)
Net Cash Used in Investing Activities	**(162,432)**	(133,162)
CASH FLOWS FROM FINANCING ACTIVITIES		
Borrowings from Debt	**50,000**	20,000
Repayments of Debt	**(40,000)**	
Net Proceeds from Sale of Common Stock	**149**	2,240
Stock-Based Compensation Tax Benefit		4,642
Dividends Paid	**(3,103)**	(2,930)
Net Cash Provided by Financing Activities	**7,046**	23,952
Net Increase / (Decrease) in Cash and Cash Equivalents	**(2,852)**	23,494
Cash and Cash Equivalents, Beginning of Period	**28,101**	18,498
Cash and Cash Equivalents, End of Period	**$ 25,249**	$ 41,992

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 2008 Annual Report to Stockholders and its Annual Report on Form 10-K for the year ended December 31, 2008 (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 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.

With respect to the unaudited financial information of the Company for the three-month periods ended March 31, 2009 and 2008, 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 April 30, 2009 appearing herein states that they did not audit and they do not express an opinion on that unaudited financial information. Accordingly, the degree of reliance on their report on such information should be restricted in light of the limited nature of the review procedures applied. PricewaterhouseCoopers LLP is not subject to the liability provisions of Section 11 of the Securities Act of 1933 for their report on the unaudited financial information because that report is not a report or a part of the registration statement prepared or certified by PricewaterhouseCoopers LLP within the meaning of Sections 7 and 11 of the Act.

Recently Adopted Accounting Standards

In February 2008, the Financial Accounting Standards Board (FASB) issued FASB Staff Position (FSP) No. FAS 157-2, Effective Date of FASB Statement No. 157, which granted a one year deferral (to fiscal years beginning after November 15, 2008, and interim periods within those fiscal years) for certain non-financial assets and liabilities measured on a nonrecurring basis to comply with SFAS No. 157. Effective January 1, 2009, the Company applied the provisions of Statement of Financial Accounting Standards (SFAS) No. 157 covered under FSP No. FAS 157-2 which did not have a material impact on the Company s financial statements. For further information, please refer to Note 7 of the Notes to the Condensed Consolidated Financial Statements.

Effective January 1, 2009, the Company adopted FSP No. Emerging Issues Task Force (EITF) 03-6-1, Determining Whether Instruments Granted in Share-Based Payment Transactions Are Participating Securities which did not have a material impact on the Company s financial statements. For further information, please refer to Note 5 of the Notes to the Condensed Consolidated Financial Statements.

In March 2008, the FASB issued SFAS No. 161, Disclosures about Derivative Instruments and Hedging Activities, an amendment of FASB Statement No. 133. The Company adopted SFAS No. 161 as of January 1, 2009. The principal impact was to require the expansion of its disclosure regarding its derivative instruments. For further information, please refer to Derivative Instruments and Hedging Activity in Note 7 of the Notes to the Condensed Consolidated Financial Statements.

Recently Issued Accounting Pronouncements

In April 2009, the FASB issued FSP No. FAS 157-4, Determining Fair Value When the Volume and Level of Activity for the Asset or Liability Have Significantly Decreased and Identifying Transactions That Are Not Orderly, which provides additional guidance in accordance with SFAS No. 157. If an entity determines that either the volume or level of activity for an asset or liability has significantly decreased from normal conditions, or that price quotations or observable inputs are not associated with orderly transactions, increased analysis and management judgment will be required to estimate fair value. The objective in fair value measurement remains unchanged from what is prescribed in SFAS No. 157 and should be reflective of the current exit price. Disclosures in interim and annual periods must include inputs and valuation techniques used to measure fair value, along with any changes in valuation techniques and related inputs during the period. In addition, disclosures for debt and equity securities must be provided on a more disaggregated basis than what was required in FAS No. 157. FSP No.

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FAS 157-4 is effective for interim and annual reporting periods ending after June 15, 2009. The Company does not expect FSP No. FAS 157-4 to have a material impact on its financial position, results of operations or cash flows.

In April 2009, the FASB issued FSP No. FAS 107-1 and Accounting Principles Bulletin (APB) No. 28-1, Interim Disclosures about Fair Value of Financial Instruments, to require disclosures about fair value of financial instruments for publicly traded companies for both interim and annual periods. Historically, these disclosures were only required annually. The interim disclosures are intended to provide financial statement users with more timely and transparent information about the effects of current market conditions on an entity s financial instruments that are not otherwise reported at fair value. FSP No. FAS 107-1 is effective for interim reporting periods ending after June 15, 2009. Comparative disclosures are only required for periods ending after the initial adoption. The Company does not expect FSP No. FAS 107-1 to have a material impact on its financial position, results of operations or cash flows.

In April 2009, the FASB issued FSP No. FAS 115-2 and FAS 124-2, Recognition and Presentation of Other-Than-Temporary Impairments, which amends the other-than-temporary impairment guidance for debt securities to make the guidance more operational and to improve the presentation and disclosure of other-than-temporary impairments on debt and equity securities in the financial statements. FSP No. FAS 115-2 and FAS 124-2 does not amend existing recognition and measurement guidance for equity securities, but does establish a new method of recognizing and reporting for debt securities. Disclosure requirements for impaired debt and equity securities have been expanded significantly and will now be required quarterly, as well as annually. FSP No. FAS 115-2 and FAS 124-2 is effective for interim and annual reporting periods ending after June 15, 2009. Comparative disclosures are only required for periods ending after the initial adoption. The Company does not expect FSP No. FAS 115-2 and FAS 124-2 to have a material impact on its financial position, results of operations or cash flows.

In December 2008, the SEC issued Release No. 33-8995, Modernization of Oil and Gas Reporting, which amends the oil and gas disclosures for oil and gas producers contained in Regulations S-K and S-X, as well as adding a section to Regulation S-K (Subpart 1200) to codify the revised disclosure requirements in Securities Act Industry Guide 2, which is being phased out. The goal of Release No. 33-8995 is to provide investors with a more meaningful and comprehensive understanding of oil and gas reserves. Energy companies affected by Release No. 33-8995 will be required to price proved oil and gas reserves using the unweighted arithmetic average of the price on the first day of each month within the 12-month period prior to the end of the reporting period, unless prices are defined by contractual arrangements, excluding escalations based on future conditions. SEC Release No. 33-8995 is effective beginning January 1, 2010. We are currently evaluating what impact Release No. 33-8995 may have on our financial position, results of operations or cash flows.

2. PROPERTIES AND EQUIPMENT, NET

Properties and equipment, net are comprised of the following:

(In thousands)	**March 31, 2009**	**December 31, 2008**
Unproved Oil and Gas Properties	**$ 308,875**	$ 315,782
Proved Oil and Gas Properties	**3,924,767**	3,813,014
Gathering and Pipeline Systems	**273,614**	274,192
Land, Building and Other Equipment	**70,020**	68,606
	4,577,276	4,471,594
Accumulated Depreciation, Depletion and Amortization	**(1,386,171)**	(1,335,766)
	$ 3,191,105	$ 3,135,828

At March 31, 2009, 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.

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The Company recognized a $12.7 million gain on sale of assets in the first quarter of 2009 primarily related to the sale of Thornwood properties in the East region. Cash proceeds of $11.4 million were received from the sale of the Thornwood properties.

On April 9, 2009, the Company entered into a definitive agreement to sell its Canadian properties to a private Canadian company. The agreement provides for total consideration (based on the exchange rate on April 9, 2009) of approximately $83 million, consisting of $63 million in cash and common stock of the Canadian company with an estimated value of $20 million. The total net book value of the Canadian properties to be sold was $89.8 million as of March 31, 2009. At December 31, 2008, the Company recorded 40.4 Bcfe of proved reserves (two percent of total proved reserves) related to these properties. The sale is expected to close on, or before, May 1, 2009 and is subject to due diligence and other customary closing conditions. The criteria for classifying these Canadian properties as assets held for sale had not been met as of March 31, 2009.

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3. ADDITIONAL BALANCE SHEET INFORMATION

Certain balance sheet amounts are comprised of the following:

(In thousands)	March 31, 2009	December 31, 2008
ACCOUNTS RECEIVABLE, NET		
Trade Accounts	**$ 56,792**	$ 94,164
Joint Interest Accounts	**18,824**	16,454
Current Income Tax Receivable		526
Other Accounts	**3,104**	1,987
	78,720	113,131
Allowance for Doubtful Accounts	**(3,502)**	(3,518)
	$ 75,218	$ 109,613
INVENTORIES		
Natural Gas in Storage	**$ 6,726**	$ 27,478
Tubular Goods and Well Equipment	**19,280**	16,439
Pipeline Imbalances	**1,612**	1,760
	$ 27,618	$ 45,677
OTHER CURRENT ASSETS		
Drilling Advances	**$ 3,188**	$ 4,869
Prepaid Balances	**6,869**	7,631
Other	**242**	
	$ 10,299	$ 12,500
OTHER ASSETS		
Rabbi Trust Deferred Compensation Plan	**$ 8,435**	$ 8,651
Other Accounts	**5,661**	6,092
	$ 14,096	$ 14,743
ACCOUNTS PAYABLE		
Trade Accounts	**$ 19,944**	$ 44,088
Natural Gas Purchases	**3,202**	5,346
Royalty and Other Owners	**36,981**	42,349
Capital Costs	**69,178**	117,029
Taxes Other Than Income	**3,659**	5,617
Drilling Advances	**1,130**	1,289
Wellhead Gas Imbalances	**3,994**	3,354
Other Accounts	**4,865**	3,913
	$ 142,953	$ 222,985
ACCRUED LIABILITIES		
Employee Benefits	**$ 4,101**	$ 10,807
Current Liability for Pension Benefits	**245**	245

Current Liability for Postretirement Benefits	**642**	642
Taxes Other Than Income	**21,849**	16,582
Interest Payable	**11,271**	20,684
Other Accounts	**2,117**	1,591
	$ 40,225	$ 50,551
OTHER LIABILITIES		
Rabbi Trust Deferred Compensation Plan	**$ 13,692**	$ 14,531
Accrued Plugging and Abandonment Liability	**28,723**	27,978
Other Accounts	**4,993**	4,717
	$ 47,408	$ 47,226

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4. LONG-TERM DEBT

The Company s debt consisted of the following:

(In thousands)	March 31, 2009	December 31, 2008
Long-Term Debt		
7.19% Notes	**$ 20,000**	$ 20,000
7.33% Weighted-Average Fixed Rate Notes	**170,000**	170,000
6.51% Weighted-Average Fixed Rate Notes	**425,000**	425,000
9.78% Notes	**67,000**	67,000
Credit Facility	**195,000**	185,000
Current Maturities		
7.19% Notes	**(20,000)**	(20,000)
Credit Facility	**(16,714)**	(15,857)
Total Current Maturities	**(36,714)**	(35,857)
Long-Term Debt, excluding Current Maturities	**$ 840,286**	$ 831,143

At March 31, 2009, the Company had $195 million of borrowings outstanding under its then-existing revolving credit facility at a weighted-average interest rate of 4.0%. The credit facility provided for an available credit line of $350 million. In April 2009, the Company entered into a new revolving credit facility and terminated the prior credit facility. See Note 11 of the Notes to the Condensed Consolidated Financial Statements for further details.

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

5. EARNINGS PER COMMON SHARE

Effective January 1, 2009, the Company adopted FSP No. EITF 03-6-1, Determining Whether Instruments Granted in Share-Based Payment Transactions Are Participating Securities. Under this FSP, unvested share-based payment awards that contain nonforfeitable rights to dividends or dividend equivalents, whether they are paid or unpaid, are considered participating securities and should be included in the computation of earnings per share pursuant to the two-class method. FSP No. EITF 03-6-1 became effective for financial statements issued for fiscal years beginning after December 15, 2008, and interim periods within those years. In addition, all prior period earnings per share data presented are required to be retrospectively adjusted. Upon adoption of FSP No. EITF 03-6-1, basic earnings per share (EPS) is required to be computed using the two-class method prescribed in SFAS No. 128, Earnings per Share. The two-class method is an earnings allocation formula that treats a participating security as having rights to earnings that would otherwise have been available to common shareholders. SFAS No. 128 defines participating securities as securities that may participate in dividends with common stocks according to a predetermined formula. FSP No. EITF 03-6-1 provides that its provisions need not be applied to immaterial items. The Company has concluded that there are no material items to consider for purposes of its shares outstanding and EPS calculations, and the treasury stock method will continue to be used, as described below.

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 stock options and stock awards outstanding at the end of the applicable period were exercised for common stock.

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The following is a calculation of basic and diluted weighted-average shares outstanding for the three months ended March 31, 2009 and 2008:

	Three Months Ended March 31,	
	2009	**2008**
Weighted-Average Shares Basic	**103,520,914**	97,715,970
Dilution Effect of Stock Options and Awards at End of Period	**589,791**	1,208,805
Weighted-Average Shares Diluted	**104,110,705**	98,924,775
Weighted-Average Stock Awards and Shares Excluded from Diluted Earnings per Share due to the Anti-Dilutive Effect	**933,426**	226,264

6. COMMITMENTS AND CONTINGENCIES

Contingencies

The Company is a defendant in various legal proceedings arising in the normal course of its business. All known liabilities are accrued based on management s best estimate of the potential loss. 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.

Commitment and Contingency Reserves

When deemed necessary, the Company establishes reserves for certain legal proceedings. The establishment of a reserve involves an estimation process that includes the advice of legal counsel and subjective judgment of management. While management believes these reserves to be adequate, it is reasonably possible that the Company could incur approximately $2.8 million of additional loss with respect to those matters in which reserves have been established. Future changes in the facts and circumstances could result in the actual liability exceeding the estimated ranges of loss and amounts accrued.

While the outcome and impact 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 condensed consolidated financial position or cash flow of the Company. Operating results, however, could be significantly impacted in the reporting periods in which such matters are resolved.

Firm Gas Transportation Agreements

The Company has incurred, and will incur over the next several years, demand charges on firm gas transportation agreements. These agreements provide firm transportation capacity rights on pipeline systems in Canada, the West and East regions. The remaining terms on these agreements range from less than one year to approximately 20 years and require the Company to pay transportation demand charges regardless of the amount of pipeline capacity utilized by the Company. If the Company does not utilize the capacity, it can release it to others, thus reducing its potential liability.

As previously disclosed in the Form 10-K, obligations under firm gas transportation agreements in effect at December 31, 2008 were $94.7 million. As of March 31, 2009, obligations under firm gas transportation agreements were $94.0 million. For further information on these future obligations, please refer to Note 7 of the Notes to the Consolidated Financial Statements in the Form 10-K.

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Drilling Rig Commitments

In the Form 10-K, the Company disclosed that it had total commitments of $44.3 million on eight drilling rigs in the Gulf Coast that are under contracts with initial terms of greater than one year. The Company entered into a new drilling rig commitment of $8.0 million in the first quarter of 2009. As of March 31, 2009, the total commitment for nine drilling rigs was $53.9 million. For further information on these future obligations, please refer to Note 7 of the Notes to the Consolidated Financial Statements in the Form 10-K.

7. FINANCIAL INSTRUMENTS

Fair Value Measurements

In February 2008, the FASB issued FSP No. FAS 157-2, Effective Date of FASB Statement No. 157, which granted a one year deferral (to fiscal years beginning after November 15, 2008, and interim periods within those fiscal years) for certain non-financial assets and liabilities measured on a nonrecurring basis to comply with SFAS No. 157. Effective January 1, 2009, the Company applied the provisions of FAS No. 157 covered under FSP No. 157-2 which did not have a material impact on the Company s financial statements. In the future, areas that could cause an impact would primarily be limited to asset impairments including goodwill, other long-lived assets, asset retirement obligations and assets acquired and liabilities assumed in a business combination, if any.

SFAS No. 157, Fair Value Measurements, established a formal framework for measuring fair values of assets and liabilities in financial statements that are already required by United States generally accepted accounting principles to be measured at fair value. As defined in SFAS No. 157, 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. SFAS No. 157 establishes a 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. For further information regarding the fair value hierarchy and SFAS No. 157, refer to Note 11 of the Notes to the Consolidated Financial Statements in the Form 10-K.

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In accordance with SFAS No. 157, the Company has classified its assets and liabilities into these levels depending upon the data relied on to determine the fair values. The fair values of the Company s natural gas and crude oil price collars and swaps are designated as Level 3. The following fair value hierarchy table presents information about the Company s assets and liabilities measured at fair value on a recurring basis as of March 31, 2009:

(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 March 31, 2009
Assets				
Rabbi Trust Deferred Compensation Plan	$ 8,435	$	$	**$ 8,435**
Derivative Contracts			405,186	**405,186**
Total Assets	$ 8,435	$	$ 405,186	**$ 413,621**
Liabilities				
Rabbi Trust Deferred Compensation Plan	$ 13,692	$	$	**$ 13,692**
Derivative Contracts				
Total Liabilities	$ 13,692	$	$	**$ 13,692**

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

The determination of the fair values above incorporates various factors required under SFAS No. 157. These factors include not only the credit standing of the counterparties involved in transactions with the Company resulting in receivables on the Company s Condensed Consolidated Balance Sheet, but also the impact of the Company s nonperformance risk on its liabilities.

The following table sets forth a reconciliation of changes for the three month periods ended March 31, 2009 and 2008 in the fair value of financial assets and liabilities classified as Level 3 in the fair value hierarchy:

	Three Months Ended March 31,	
(In thousands)	2009	2008
Balance at beginning of period[1]	**$ 355,202**	$ 7,272
Total Gains or (Losses) (Realized or Unrealized):		
Included in Earnings[2]	**90,035**	(1,022)
Included in Other Comprehensive Income	**49,043**	(92,659)
Purchases, Issuances and Settlements	**(89,094)**	1,022
Transfers In and/or Out of Level 3		
Balance at end of period	**$ 405,186**	$ (85,387)

(1) Net derivatives for Level 3 at December 31, 2008 was entirely comprised of derivative assets. Net derivatives at December 31, 2007 included derivative assets of $12.7 million and derivative liabilities of $5.4 million.

(2) A gain of $0.9 million for the three months ended March 31, 2009 was unrealized and included in Natural Gas Production Revenues in the Statement of Operations at March 31, 2009. All gains included in earnings for the three months ended March 31, 2008 were realized.

The derivative contracts were measured based on quotes from the Company s counterparties. Such quotes have been derived using a Black-Scholes model that considers various inputs including current market and contractual prices for the underlying instruments, quoted forward prices for natural gas and crude oil, volatility factors and

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interest rates, such as a LIBOR curve for a similar length of time as the derivative contract term. Although the Company utilizes multiple quotes to assess the reasonableness of its values, the Company has not attempted to obtain sufficient corroborating market evidence to support classifying these derivative contracts as Level 2. The Company measured the nonperformance risk of its counterparties by reviewing credit default swap spreads for the various financial institutions in which it has derivative transactions. The resulting reduction to the net receivable derivative contract position was $7.4 million. In times where the Company has net derivative contract liabilities, the nonperformance risk of the Company is evaluated using a market credit spread provided by the Company s bank.

Derivative Instruments and Hedging Activity

In March 2008, the FASB issued SFAS No. 161, Disclosures about Derivative Instruments and Hedging Activities, an amendment of FASB Statement No. 133. SFAS No. 161 requires entities to provide greater transparency about how and why the entity uses derivative instruments, how the instruments and related hedged items are accounted for under SFAS No. 133 and how the instruments and related hedged items affect the financial position, results of operations and cash flows of the entity. The Company adopted SFAS No. 161 effective January 1, 2009. A tabular format including the fair value of derivative instruments and their gains and losses, disclosure about credit risk-related derivative features and cross-referencing within the footnotes are also new requirements.

The Company periodically enters into derivative commodity 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 March 31, 2009, the Company had 26 cash flow hedges open: 14 natural gas price collar arrangements, 10 natural gas price swap arrangements and two crude oil price swap arrangements. During the first quarter of 2009, the Company entered into six new derivative contracts covering anticipated natural gas production for 2012. These natural gas basis swaps did not qualify for hedge accounting under SFAS No. 133. These natural gas basis swaps mitigate the risk associated with basis differentials that may expand or increase over time, thus reducing the exposure and risk of basis fluctuations.

As of March 31, 2009, the Company had the following outstanding commodity derivatives:

Commodity	Derivative Type	Weighted-Average Contract Price [1]		Volume		Contract Period
Derivatives designated as Hedging Instruments under Statement 133						
Natural Gas	Swap	$12.18	per Mcf	16,079	Mmcf	2009
Natural Gas	Swap	$11.43	per Mcf	19,295	Mmcf	2010
Natural Gas	Collar	$12.39 / $9.40	per Mcf	47,253	Mmcf	2009
Crude Oil	Swap	$125.25	per Bbl	365	Mbbl	2009
Crude Oil	Swap	$125.00	per Bbl	365	Mbbl	2010
Derivatives not qualifying as Hedging Instruments under Statement 133						
Natural Gas	Basis Swap	$(0.27)	per Mcf	16,123	Mmcf	2012

[1] For collar derivatives, the amounts in this column represent the ceiling and floor prices.

The change in the fair value of derivatives designated as hedges that is effective is initially recorded to Accumulated Other Comprehensive Income / (Loss) in Stockholders Equity in the Balance Sheet. The ineffective portion of the change in the fair value of derivatives designated as hedges, and the change in fair value of all other derivatives, are recorded currently in earnings as a component of Natural Gas Production and Crude Oil and Condensate Revenue, as appropriate.

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The following schedules reflect the fair values of derivative instruments on the Company s condensed consolidated financial statements as of March 31, 2009:

Effect of derivative instruments on the Condensed Consolidated Balance Sheet

	Asset Derivatives		Liability Derivatives	
(In thousands)	**Balance Sheet Location**	**Fair Value**	**Balance Sheet Location**	**Fair Value**
Derivatives designated as Hedging Instruments under Statement 133				
Natural Gas Commodity Contracts	Current Derivative Contracts	$ 291,453		$
Natural Gas Commodity Contracts	Long-Term Derivative Contracts	69,181		
Crude Oil Commodity Contracts	Current Derivative Contracts	27,237		
Crude Oil Commodity Contracts	Long-Term Derivative Contracts	16,374		
		$ 404,245		
Derivatives not qualifying as Hedging Instruments under Statement 133				
Natural Gas Commodity Basis Contracts	Long-Term Derivative Contracts	941		
		$ 405,186		

At March 31, 2009, a $404.3 million ($253.5 million, net of tax) unrealized gain was recorded in Accumulated Other Comprehensive Income / (Loss). For the natural gas commodity basis contracts that were not designated as hedging instruments, a $0.9 million unrealized gain was recorded in the Condensed Consolidated Statement of Operations as a component of Natural Gas Production Revenue for the quarter ended March 31, 2009.

Effect of derivative instruments on the Condensed Consolidated Statement of Operations

(In thousands)	**Amount of Gain Recognized in OCI on Derivative (Effective Portion)**	**Location of Gain Reclassified from Accumulated OCI into Income (Effective Portion)**	**Amount of Gain Reclassified from Accumulated OCI into Income (Effective Portion)**	**Location of Gain Recognized in Income on Derivative (Ineffective Portion and Amount Excluded from Effectiveness Testing)**
Derivatives designated as Hedging Instruments under Statement 133				
Natural Gas Commodity Contracts	$ 360,634	Natural Gas Production Revenues	$ 81,710	N/A
Crude Oil Commodity Contracts	43,611	Crude Oil and Condensate Revenues	7,384	N/A
	$ 404,245		**$ 89,094**	

(In thousands)	**Location of Gain Recognized in Income on Derivative**	**Amount of Gain Recognized in Income on Derivative**
Derivatives not qualifying as Hedging Instruments under Statement 133		
Natural Gas Commodity Contracts	Natural Gas Production Revenues	**$ 941**

Based upon estimates at March 31, 2009, the Company would expect to reclassify from Other Comprehensive Income to the Condensed Consolidated Statement of Operations over the next 12 months $199.8 million in after-tax income associated with its commodity hedges. This reclassification represents the net short-term receivable (after the impact of taxes) associated with open positions currently not reflected in earnings at March 31, 2009 related to anticipated 2009 and 2010 production.

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8. 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 month periods ended March 31, 2009 and 2008:

	Three Months Ended March 31,			
(In thousands)	**2009**		**2008**	
Accumulated Other Comprehensive Income / (Loss) Beginning of Period		**$ 186,426**		$ (894)
Net Income	**$ 47,580**		$ 45,975	
Other Comprehensive Income / (Loss), net of taxes:				
Reclassification Adjustment for Settled Contracts, net of taxes of $33,231 and $(379), respectively	**(55,863)**		643	
Changes in Fair Value of Hedge Positions, net of taxes of $(51,881) and $34,778, respectively	**86,256**		(58,903)	
Defined Benefit Pension and Postretirement Plans:				
Amortization of Net Obligation at Transition, net of taxes of $(59) and $(59), respectively	**$ 99**		$ 99	
Amortization of Prior Service Cost, net of taxes of $(67) and $(93), respectively	**113**		158	
Amortization of Net Loss, net of taxes of $(359) and $(128), respectively	**604**	**816**	218	475
Foreign Currency Translation Adjustment, net of taxes of $584 and $1,358, respectively		**(951)**		(2,193)
Total Other Comprehensive Income / (Loss)		**30,258**		(59,978)
		30,258		(59,978)
Comprehensive Income / (Loss)	**$ 77,838**		$ (14,003)	
Accumulated Other Comprehensive Income / (Loss) - End of Period		**$ 216,684**		$ (60,872)

Changes in the components of Accumulated Other Comprehensive Income / (Loss), net of taxes, for the three months ended March 31, 2009 were as follows:

Accumulated Other Comprehensive Income, net of taxes *(In thousands)*	**Net Gains on Cash Flow Hedges**	**Defined Benefit Pension and Postretirement Plans**	**Foreign Currency Translation Adjustment**	**Total**
Balance at December 31, 2008	$ 223,068	$ (29,608)	$ (7,034)	$ 186,426
Net change in unrealized gain on cash flow hedges, net of taxes of $(18,650)	30,393			30,393
Net change in defined benefit pension and postretirement plans, net of taxes of $(485).		816		816
Change in foreign currency translation adjustment, net of taxes of $584			(951)	(951)
Balance at March 31, 2009	**$ 253,461**	**$ (28,792)**	**$ (7,985)**	**$ 216,684**

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9. PENSION AND OTHER POSTRETIREMENT BENEFITS

The components of net periodic benefit costs for the three months ended March 31, 2009 and 2008 were as follows:

	Three Months Ended March 31,	
(In thousands)	**2009**	**2008**
Qualified and Non-Qualified Pension Plans		
Current Period Service Cost	**$ 861**	$ 828
Interest Cost	**928**	818
Expected Return on Plan Assets	**(671)**	(884)
Amortization of Prior Service Cost	**13**	13
Amortization of Net Loss	**794**	294
Net Periodic Pension Cost	**$ 1,925**	$ 1,069
Postretirement Benefits Other than Pension Plans		
Current Period Service Cost	**$ 320**	$ 235
Interest Cost	**398**	308
Amortization of Prior Service Cost	**167**	238
Amortization of Net Loss	**169**	52
Amortization of Net Obligation at Transition	**158**	158
Total Postretirement Benefit Cost	**$ 1,212**	$ 991

Employer Contributions

The funding levels of the pension and postretirement 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 2009. The Company previously disclosed in its financial statements for the year ended December 31, 2008 that it expected to contribute $0.3 million to its non-qualified pension plan and $0.8 million to the postretirement benefit plan during 2009. It is anticipated that these contributions will be made prior to December 31, 2009. Currently, management has not determined if any additional discretionary funding will be made in 2009.

10. STOCK-BASED COMPENSATION

Compensation expense charged against income for stock-based awards (including the supplemental employee incentive plans) during the first quarter of 2009 and 2008 was $5.1 million and $17.6 million, respectively, and is included in General and Administrative Expense in the Condensed Consolidated Statement of Operations.

As disclosed in the Form 10-K, the Company realized a $10.7 million tax benefit during the year ended December 31, 2008 related to the 2007 federal tax deduction in excess of book compensation cost for employee stock-based compensation. In accordance with SFAS No. 123(R), the Company is able to recognize this tax benefit only to the extent it reduces the Company s income taxes payable. Such income tax benefit related to the stock-based compensation was recorded in 2008 as the Company carried back net operating losses concurrent with the 2007 tax return filing. For regular tax purposes, the Company was in a net operating loss position in 2008 and estimates that it will be in a net operating loss position in 2009; thus, the entire tax benefits related to 2009 and 2008 employee stock-based compensation will be recorded only when the tax net operating loss is utilized to reduce income taxes payable or claim a refund of taxes paid in prior years.

For further information regarding Stock-Based Compensation or the Company s Incentive Plans, please refer to Note 10 of the Notes to the Consolidated Financial Statements in the Form 10-K.

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Restricted Stock Awards

During the first quarter of 2009, the Compensation Committee granted 6,000 restricted stock awards with a weighted-average grant date per share value of $30.44. The fair value of restricted stock grants is based on the average of the high and low stock price on the grant date.

Compensation expense recorded for all unvested restricted stock awards for the first quarter of 2009 and 2008 was $0.2 million and $0.7 million, respectively. The Company used an annual forfeiture rate ranging from 0% to 7.1% based on approximately ten years of the Company s history for this type of award to various employee groups.

Restricted Stock Units

During the quarter ended March 31, 2009, 33,150 restricted stock units were granted to non-employee directors of the Company with a grant date per share value of $22.63. The fair value of these units is measured at the average of the high and low stock price on grant date and compensation expense is recorded immediately. These units immediately vest and are paid out when the director ceases to be a director of the Company. The compensation cost, which reflects the total fair value of these units, recorded in the first quarter of 2009 and 2008 was $0.8 million in each period.

Stock Appreciation Rights

During the first quarter of 2009, the Compensation Committee granted 221,780 stock appreciation rights (SARs) to employees. These awards allow the employee to receive the intrinsic value over the $22.63 grant date market price that may result from the price appreciation on a set number of common shares during the contractual term of seven years. As these SARs are paid out in stock, rather than in cash, the Company calculates the fair value in the same manner as stock options, by using a Black-Scholes model.

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

	Three Months Ended March 31, 2009
Weighted-Average Value per Stock Appreciation Right Granted During the Period	$ 9.35
Assumptions	
Stock Price Volatility	50.5%
Risk Free Rate of Return	1.7%
Expected Dividend	0.5%
Expected Term (in years)	4.5

Compensation expense recorded during the first quarter of 2009 and 2008 for SARs was $1.0 million and $0.8 million, respectively. Included in these amounts were $0.7 million and $0.5 million in the first quarter of 2009 and 2008, respectively, related to the immediate expensing of shares granted in 2009 and 2008 to retirement-eligible employees.

Performance Share Awards

During 2009, the Compensation Committee granted three types of performance share awards to employees for a total of 785,350 performance shares. The performance period for two of the three types of these awards commenced on January 1, 2009 and ends December 31, 2011. Both of these types of awards vest on January 1, 2012.

Awards totaling 207,730 performance shares are earned, or not earned, based on the comparative performance of the Company s common stock measured against sixteen other companies in the Company s peer group over a three year performance period. The grant date per share value of the equity portion of this award was $17.63. Depending on

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the Company s performance, employees may receive an aggregate of up to 100% of the fair market value of a share of common stock payable in common stock plus up to 100% of the fair market value of a share of common stock payable in cash.

Awards totaling 376,510 performance shares are earned, or not earned, based on the Company s internal performance metrics rather than performance compared to a peer group. The grant date per share value of this award was $22.63. These awards represent the right to receive up to 100% of the award in shares of common stock. The actual number of shares issued at the end of the performance period will be determined based on the Company s performance against three performance criteria set by the Company s Compensation Committee. An employee will earn one-third of the award granted for each internal performance metric that the Company meets at the end of the performance period. These performance criteria measure the Company s average production, average finding costs and average reserve replacement over three years. Based on the Company s probability assessment at March 31, 2009, it is considered probable that these three criteria will be met.

The third type of performance share award, totaling 201,110 performance shares, with a grant date per share value of $22.63, has a three-year graded vesting schedule, vesting one-third 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 have $100 million or more of operating cash flow for the year preceding a vesting date, then the portion of the performance shares that would have vested on that date will be forfeited. As of March 31, 2009, it is considered probable that this performance metric will be met.

For all performance share awards granted to employees in 2009 and 2008, an annual forfeiture rate ranging from 0% to 5.2% has been assumed based on the Company s history for this type of award to various employee groups.

For awards that are based on the internal metrics (performance condition) of the Company and for awards that were granted prior to the adoption of SFAS No. 123(R) on January 1, 2006, fair value is measured based on the average of the high and low stock price of the Company on grant date and expense is amortized over the three year vesting period. To determine the fair value for awards that were granted after January 1, 2006 that are based on the Company s comparative performance against a peer group (market condition), the equity and liability components are bifurcated. On the grant date, the equity component was valued using a Monte Carlo binomial model and is amortized on a straight-line basis over three years. The liability component is valued at each reporting period by using a Monte Carlo binomial model.

The four primary inputs for the Monte Carlo model are the risk-free rate, volatility of returns, correlation in movement of total shareholder return and the expected dividend. An interpolated risk-free rate was generated from the Federal Reserve website for constant maturity treasuries for two and three year bonds (as of the reporting date) set equal to the remaining duration of the performance period. Volatility was set equal to the annualized daily volatility for the remaining duration of the reporting period ending on the reporting date. Correlation in movement of total shareholder return was determined based on a correlation matrix that was created which identifies total shareholder return correlations for each pair of companies in the peer group, including the Company. The paired returns in the correlation matrix ranged from approximately 59% to approximately 88% for the Company and its peer group. The expected dividend is calculated using the total Company annual dividends expected to be paid ($0.12 per share) divided by the March 31, 2009 closing price of the Company s stock ($23.57). Based on these inputs discussed above, a ranking was projected identifying the Company s rank relative to the peer group for each award period.

The following assumptions were used as of March 31, 2009 for the Monte Carlo model to value the liability components of the peer group measured performance share awards. The equity portion of the award was valued on the date of grant using the Monte Carlo model and this portion was not marked to market.

	March 31, 2009
Risk Free Rate of Return	**0.5%-1.1%**
Stock Price Volatility	**59.4% - 86.6%**
Expected Dividend	**0.5%**

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The Monte Carlo value per share for the liability component for all outstanding market condition performance share awards ranged from $9.22 to $10.76 at March 31, 2009. The long-term liability for market condition performance share awards, included in Other Liabilities in the Condensed Consolidated Balance Sheet, at March 31, 2009 and December 31, 2008 was $0.6 million and $0.3 million, respectively. The short-term liability, included in Accrued Liabilities in the Condensed Consolidated Balance Sheet, at March 31, 2009 and December 31, 2008, for market condition performance share awards was $0.7 million and $2.5 million, respectively.

During the first quarter of 2009, 322,340 performance shares vested. As discussed in Note 10 of the Notes to the Consolidated Financial Statements in the Form 10-K, the performance period ended on December 31, 2008 for two types of performance shares awarded in 2006. A total of 105,800 shares measured based on the Company s performance against a peer group (valued at $1.7 million) were awarded in addition to cash of $1.8 million. A total of 155,800 shares measured based on internal performance metrics of the Company (valued at $3.8 million) were also awarded. The remaining 60,740 shares that vested in the first quarter of 2009 (valued at $2.5 million) represent one-third of the three-year graded vesting schedule performance share awards granted in 2008 and 2007 with a grant date per share value of $48.48 and $35.22, respectively. These awards met the performance criteria that the Company had positive operating income for 2008 and 2007.

As of March 31, 2009, 256,400 shares of the Company s common stock representing vested performance share awards were deferred into the Rabbi Trust Deferred Compensation Plan. For the first quarter of 2009, a reduction to the rabbi trust deferred compensation liability of $0.6 million was recognized, representing the decrease in the closing price of all shares from December 31, 2008 to March 31, 2009. This reduction in stock-based compensation expense was included in General and Administrative expense in the Condensed Consolidated Statement of Operations.

Total compensation cost recognized for both the equity and liability components of all performance share awards as well as expense related to the shares deferred into the rabbi trust during the three months ended March 31, 2009 and 2008 was $3.1 million and $10.8 million, respectively.

11. SUBSEQUENT EVENT

On April 24, 2009, the Company entered into a new revolving credit facility and terminated its prior credit facility. See Note 4 of the Notes to the Condensed Consolidated Financial Statements. The credit facility provides for an available credit line of $500 million and contains an accordion feature allowing the Company to increase the available credit line to $600 million, if any one or more of the existing banks or new banks agree to provide such increased commitment amount. The term of the facility expires in April 2012.

The credit facility is unsecured. The available credit line is subject to adjustment from time to time on the basis of (1) the projected present value (as determined by the banks based on the Company s reserve reports and engineering reports) of estimated future net cash flows from certain proved oil and gas reserves and certain other assets of the Company (the Borrowing Base) and (2) the outstanding principal balance of the Company s senior notes. Under the credit facility, the Borrowing Base is initially set at $1.35 billion, to be periodically redetermined as described above. While the Company does not expect a reduction in the available credit line, in the event that it is adjusted below the outstanding level of borrowings, the Company has a period of six months to reduce its outstanding debt to the adjusted credit line available. Interest rates under the credit facility are based on Euro-Dollars (LIBOR) or Base Rate (Prime) indications, plus a margin. These associated margins increase if the total indebtedness is greater than 25%, greater than 50%, greater than 75% or greater than 90% of the Borrowing Base, as shown below:

	Debt Percentage				
	<25%	**≥ 25% <50%**	**≥ 50% <75%**	**≥ 75% <90%**	**≥ 90%**
Eurodollar Margin	2.000%	2.250%	2.500%	2.750%	3.000%
Base Rate Margin	1.125%	1.375%	1.625%	1.875%	2.125%

The credit facility provides for a commitment fee on the unused available balance at annual rates of 0.50%.

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The credit facility contains various customary restrictions, which include the following:

(a) Maintenance of a minimum annual coverage ratio of operating cash flow to interest expense for the trailing four quarters of 2.8 to 1.0.

(b) Maintenance of an asset coverage ratio of the present value of proved reserves plus working capital to debt of 1.5 to 1.0.

(c) Maintenance of a current ratio of 1.0 to 1.0.
(d) Prohibition on the merger or sale of all, or substantially all, of the Company s or any subsidiary s assets to a third party, except under certain limited conditions.

In addition, the credit facility includes a customary condition to the Company s borrowings under the facility that there has not occurred a material adverse change with respect to the Company.

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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 March 31, 2009, the related condensed consolidated statements of operations and of cash flows for the three-month periods ended March 31, 2009 and 2008. 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, 2008, and the related consolidated statements of operations, of comprehensive income, of stockholders equity, and of cash flows for the year then ended (not presented herein), and in our report dated February 27, 2009, which included an explanatory paragraph related to changes in the manner of accounting for fair value measurements and defined pension and postretirement plans, 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, 2008, 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

April 30, 2009

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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 month periods ended March 31, 2009 and 2008 should be read in conjunction with our Condensed Consolidated Financial Statements and the Notes included in this Form 10-Q and with the Consolidated Financial Statements, Notes and Management s Discussion and Analysis included in the Cabot Oil & Gas Annual Report on Form 10-K for the year ended December 31, 2008 (Form 10-K).

Overview

Operating revenues for the quarter ended March 31, 2009 increased by $14.3 million, or seven percent, from the quarter ended March 31, 2008. Natural gas production revenues increased by $18.0 million, or 11%, for the quarter ended March 31, 2009 as compared to the quarter ended March 31, 2008 due to increases in production in the Gulf Coast and, to a lesser extent, in the East, partially offset by decreased realized natural gas prices and natural gas production in the West and Canada. Crude oil and condensate revenues decreased by $2.2 million, or 14%, for the first quarter of 2009 as compared to the first quarter of 2008 due to a decrease in realized crude oil prices and, to a lesser extent, decreased crude oil production in all regions except for the Gulf Coast. Brokered natural gas revenues decreased by $2.2 million due to decreases in both sales price and, to a lesser extent, brokered volumes.

Our average realized natural gas price for the first quarter of 2009 was $7.51 per Mcf, five percent lower than the $7.92 per Mcf price realized in the first quarter of 2008. Our average realized crude oil price for the first quarter of 2009 was $75.25 per Bbl, 13% lower than the $86.55 per Bbl price realized in the first quarter of 2008. These realized prices include realized gains and losses resulting from commodity derivatives (zero-cost collars or swaps). 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.

On an equivalent basis, our production level for the quarter ended March 31, 2009 increased by 16% compared to the quarter ended March 31, 2008. For the quarter ended March 31, 2009, we produced 25.6 Bcfe compared to production of 22.2 Bcfe for the quarter ended March 31, 2008. Natural gas production was 24.5 Bcf and oil production was 189 Mbbls for the first quarter of 2009. Natural gas production increased by 16% when compared to the first quarter of 2008, which had production of 21.0 Bcf. This increase was primarily a result of increased natural gas production in the Gulf Coast region associated with the properties we acquired in east Texas in August 2008, and increased drilling in the County Line field, as well as increased production in the East region associated with an increase in the drilling program and the initiation of production in Susquehanna, Pennsylvania. Partially offsetting these increases were decreases in production in Canada due to reduced drilling activity and natural declines in both Canada and the West. Oil production decreased by one percent, from 190 Mbbls in the first quarter of 2008 to 189 Mbbls produced in the first quarter of 2009. This was primarily the result of slight declines in production in all regions except for the Gulf Coast.

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 2009, we expect to spend approximately $475 million in capital and exploration expenditures. We believe our cash on hand and operating cash flow in 2009 will be sufficient to fund our budgeted capital and exploration spending. Any additional needs will be funded by borrowings from our credit facility. We may continue to reduce our budgeted capital and exploration spending to maintain sufficient liquidity. For the three months ended March 31, 2009, approximately $128 million has been invested in our exploration and development efforts.

During the first three months of 2009, we drilled 49 gross wells (46 development, two exploratory and one extension wells) with a success rate of 96% compared to 85 gross wells (83 development, one exploratory and one extension wells) with a success rate of 98% for the comparable period of the prior year. For the full year of 2009, we plan to drill approximately 148 gross wells.

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We 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 manage our balance sheet in an effort to ensure that we have sufficient liquidity, and we intend to maintain spending discipline. We believe these strategies are appropriate for our portfolio of projects and the current industry environment and that this activity will continue to add shareholder value over the long-term.

In April 2009, we entered into a definitive agreement to sell our Canadian assets to a private Canadian company (see Note 2 of the Notes to the Condensed Consolidated Financial Statements for further details). In April 2009, we entered into a new revolving credit facility and terminated our prior credit facility (see Notes 4 and 11 of the Notes to the Condensed Consolidated Financial Statements for further details).

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

Financial Condition

Capital Resources and Liquidity

Our primary sources of cash for the quarter ended March 31, 2009 were from funds generated from the sale of natural gas and crude oil production and, to a lesser extent, asset sales and borrowings under our revolving credit facility. Cash flows provided by operating activities and, to a lesser extent proceeds from asset sales and borrowings were primarily used to fund our development and, to a lesser extent, exploratory expenditures, in addition to paying dividends. See below for additional discussion and analysis of cash flow.

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

Our working capital is also substantially influenced by variables discussed above. From time to time, our working capital will reflect a surplus, while at other times it will reflect a deficit. This fluctuation is not unusual. The recent financial and credit crisis has reduced credit availability and liquidity for some companies; however, we believe we have adequate liquidity available to meet our working capital requirements.

	Three Months Ended March 31,	
(In thousands)	**2009**	**2008**
Cash Flows Provided by Operating Activities	**$ 152,534**	$ 132,704
Cash Flows Used in Investing Activities	**(162,432)**	(133,162)
Cash Flows Provided by Financing Activities	**7,046**	23,952
Net Increase / (Decrease) in Cash and Cash Equivalents	**$ (2,852)**	$ 23,494

***Operating Activities*.** Key components impacting net operating cash flows are commodity prices, production volumes and operating costs. Net cash provided by operating activities in the first quarter of 2009 increased by $19.8 million over the first quarter of 2008. This increase was mainly due to an increase in working capital changes as a result of a decrease in trade accounts receivable due to lower commodity prices and a decrease in accounts payable due to lower capital expenditures and lower commodity prices. Average realized natural gas prices decreased by five percent for the first three months of 2009 compared to the first three months of 2008 and average realized crude oil prices decreased by 13% compared to the same period. Equivalent production volumes increased by 16% for the quarter ended March 31, 2009 compared to the quarter ended March 31, 2008 as a result of higher natural gas production. 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 continue to decline during 2009.

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Investing Activities. The primary uses of cash in investing activities were capital spending and exploration expenses. We established the budget for these amounts based on our current estimate of future commodity prices. Due to the volatility of commodity prices and new opportunities which may arise, our capital expenditures may be periodically adjusted during any given year. Cash flows used in investing activities increased by $29.2 million from the first quarter of 2008 compared to the first quarter of 2009. The increase was due to an increase of $42.9 million in capital expenditures and an increase of $1.4 million in exploration expenditures, partially offset by $15.1 million of proceeds from the sale of assets.

Financing Activities. Cash flows provided by financing activities decreased by $16.9 million from the first quarter of 2008 compared to the first quarter of 2009. This was primarily due to a decrease of $10 million in borrowings under our revolving credit facility ($10 million of net borrowings in the first quarter of 2009 compared to $20 million of net borrowings in the first quarter of 2008). Additionally, there was no tax benefit realized for stock-based compensation in the first quarter of 2009, which resulted in a decrease of $4.6 million, net proceeds from the sale of common stock decreased by $2.1 million and dividends paid increased by $0.2 million.

At March 31, 2009, we had $195 million of borrowings outstanding under our then-existing unsecured credit facility at a weighted-average interest rate of 4.0%. The credit facility provided for an available credit line of $350 million. In April 2009, we entered into a new revolving credit facility and terminated our prior credit facility (see Notes 4 and 11 to the Condensed Consolidated Financial Statements for further details). The new credit facility provides for an available credit line of $500 million and contains an accordion feature allowing us to increase the available credit line to $600 million, if any one or more of the existing banks or new banks agree to provide such increased commitment amount. The available credit line is subject to adjustment on the basis of the present value of estimated future net cash flows from proved oil and gas reserves (as determined by the banks based on our reserve reports and engineering reports) and certain other assets. We strive to manage our debt at a level below the available credit line in order to maintain excess borrowing capacity. Our revolving credit facility includes a covenant limiting our total debt. Management believes that we have the capacity to finance our spending plans and maintain our liquidity. At the same time, we will closely monitor the capital markets. As a result of market conditions and our increased level of borrowings, we may experience increased costs associated with future debt.

Capitalization

Information about our capitalization is as follows:

(Dollars in millions)	**March 31, 2009**	**December 31, 2008**
Debt[1]	**$ 877.0**	$ 867.0
Stockholders Equity	**1,868.9**	1,790.6
Total Capitalization	**$ 2,745.9**	$ 2,657.6
Debt to Capitalization	**32%**	33%
Cash and Cash Equivalents	**$ 25.2**	$ 28.1

(1) Includes $36.7 million and $35.9 million of current portion of long-term debt at March 31, 2009 and December 31, 2008, respectively. Includes $195 million and $185 million of borrowings outstanding under our revolving credit facility at March 31, 2009 and December 31, 2008, respectively.

During the quarter ended March 31, 2009, we paid dividends of $3.1 million ($0.03 per share) on our common stock. A regular dividend has been declared for each quarter since we became a public company in 1990.

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Capital and Exploration Expenditures

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

The following table presents major components of capital and exploration expenditures for the three months ended March 31, 2009 and 2008:

	Three Months Ended March 31,	
(In millions)	**2009**	**2008**
Capital Expenditures		
Drilling and Facilities[(1)]	**$ 113.5**	$ 99.5
Leasehold Acquisitions	**3.7**	6.4
Pipeline and Gathering	**2.9**	1.8
Other	**1.4**	1.1
	121.5	108.8
Exploration Expense	**6.5**	5.1
Total	**$ 128.0**	$ 113.9

(1) Includes Canadian currency translation effects of $(2.1) million and $(4.5) million in 2009 and 2008, respectively.

For the full year of 2009, we plan to drill approximately 148 gross (122.3 net) wells. This 2009 drilling program includes approximately $475 million in total capital and exploration expenditures. See the Overview discussion for additional information regarding the current year drilling program. We will continue to assess the natural gas and crude oil price environment and our liquidity position and may increase or decrease the capital and exploration expenditures accordingly.

Contractual Obligations

At March 31, 2009, we were obligated to make future payments under drilling rig commitments and firm gas transportation agreements. For further information, please refer to Firm Gas Transportation Agreements and Drilling Rig Commitments under Note 6 in the Notes to the Condensed Consolidated Financial Statements and in our Form 10-K.

Critical Accounting Policies and Estimates

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

Recently Adopted Accounting Standards

In February 2008, the Financial Accounting Standards Board (FASB) issued FASB Staff Position (FSP) No. FAS 157-2, Effective Date of FASB Statement No. 157, which granted a one year deferral (to fiscal years beginning after November 15, 2008, and interim periods within those fiscal years) for certain non-financial assets and liabilities measured on a nonrecurring basis to comply with SFAS No. 157. Effective January 1, 2009, we applied the provisions of Statement of Financial Accounting Standards (SFAS) No. 157 covered under FSP No. FAS 157-2 which did not have a material impact on our financial statements. For further information, please refer to Note 7 of the Notes to the Condensed Consolidated Financial Statements.

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Effective January 1, 2009, we adopted FSP No. Emerging Issues Task Force (EITF) 03-6-1, Determining Whether Instruments Granted in Share-Based Payment Transactions Are Participating Securities which did not have a material impact on our financial statements. For further information, please refer to Note 5 of the Notes to the Condensed Consolidated Financial Statements.

In March 2008, the FASB issued SFAS No. 161, Disclosures about Derivative Instruments and Hedging Activities, an amendment of FASB Statement No. 133. We adopted SFAS No. 161 as of January 1, 2009. The principal impact was to require the expansion of our disclosure regarding our derivative instruments. For further information, please refer to Derivative Instruments and Hedging Activity in Note 7 of the Notes to the Condensed Consolidated Financial Statements.

Recently Issued Accounting Pronouncements

In April 2009, the FASB issued FSP No. FAS 157-4, Determining Fair Value When the Volume and Level of Activity for the Asset or Liability Have Significantly Decreased and Identifying Transactions That Are Not Orderly, which provides additional guidance in accordance with SFAS No. 157. If an entity determines that either the volume or level of activity for an asset or liability has significantly decreased from normal conditions, or that price quotations or observable inputs are not associated with orderly transactions, increased analysis and management judgment will be required to estimate fair value. The objective in fair value measurement remains unchanged from what is prescribed in SFAS No. 157 and should be reflective of the current exit price. Disclosures in interim and annual periods must include inputs and valuation techniques used to measure fair value, along with any changes in valuation techniques and related inputs during the period. In addition, disclosures for debt and equity securities must be provided on a more disaggregated basis than what was required in FAS No. 157. FSP No. FAS 157-4 is effective for interim and annual reporting periods ending after June 15, 2009. We do not expect FSP No. FAS 157-4 to have a material impact on our financial position, results of operations or cash flows.

In April 2009, the FASB issued FSP No. FAS 107-1 and Accounting Principles Bulletin (APB) No. 28-1, Interim Disclosures about Fair Value of Financial Instruments, to require disclosures about fair value of financial instruments for publicly traded companies for both interim and annual periods. Historically, these disclosures were only required annually. The interim disclosures are intended to provide financial statement users with more timely and transparent information about the effects of current market conditions on an entity s financial instruments that are not otherwise reported at fair value. FSP No. FAS 107-1 is effective for interim reporting periods ending after June 15, 2009. Comparative disclosures are only required for periods ending after the initial adoption. We do not expect FSP No. FAS 107-1 to have a material impact on our financial position, results of operations or cash flows.

In April 2009, the FASB issued FSP No. FAS 115-2 and FAS 124-2, Recognition and Presentation of Other-Than-Temporary Impairments, which amends the other-than-temporary impairment guidance for debt securities to make the guidance more operational and to improve the presentation and disclosure of other-than-temporary impairments on debt and equity securities in the financial statements. FSP No. FAS 115-2 and FAS 124-2 does not amend existing recognition and measurement guidance for equity securities, but does establish a new method of recognizing and reporting for debt securities. Disclosure requirements for impaired debt and equity securities have been expanded significantly and will now be required quarterly, as well as annually. FSP No. FAS 115-2 and FAS 124-2 is effective for interim and annual reporting periods ending after June 15, 2009. Comparative disclosures are only required for periods ending after the initial adoption. We do not expect FSP No. FAS 115-2 and FAS 124-2 to have a material impact on our financial position, results of operations or cash flows.

In December 2008, the SEC issued Release No. 33-8995, Modernization of Oil and Gas Reporting, which amends the oil and gas disclosures for oil and gas producers contained in Regulations S-K and S-X, as well as adding a section to Regulation S-K (Subpart 1200) to codify the revised disclosure requirements in Securities Act Industry Guide 2, which is being phased out. The goal of Release No. 33-8995 is to provide investors with a more meaningful and comprehensive understanding of oil and gas reserves. Energy companies affected by Release No. 33-8995 will be required to price proved oil and gas reserves using the unweighted arithmetic average of the price on the first day of each month within the 12-month period prior to the end of the reporting period, unless prices are defined by contractual arrangements, excluding escalations based on future conditions. SEC Release No. 33-8995 is effective beginning January 1, 2010. We are currently evaluating what impact Release No. 33-8995 may have on our financial position, results of operations or cash flows.

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Results of Operations

First Quarters of 2009 and 2008 Compared

We reported net income in the first quarter of 2009 of $47.6 million, or $0.46 per share. For the first quarter of 2008, we reported net income of $46.0 million, or $0.47 per share. Net income increased in the first quarter of 2009 by $1.6 million, primarily due to an increase in operating revenues and gain on sale of assets in the first quarter of 2009, partially offset by increased operating, interest and income tax expenses. Operating revenues increased by $14.3 million, largely due to an increase in natural gas production revenues, partially offset by decreased brokered natural gas revenues and crude oil and condensate revenues. Operating expenses increased by $13.2 million between periods due to increases in depreciation, depletion and amortization, impairments of unproved properties, direct operations and exploration expense, partially offset by decreased general and administrative expenses, taxes other than income and brokered natural gas costs. In addition, net income was impacted by gain on sale of assets of $12.7 million as well as an increase in expenses of $12.2 million resulting from a combination of increased income tax expense and interest and other expenses. Income tax expense was higher in the first quarter of 2009 as a result of an increase in the effective tax rate.

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Natural Gas Production Revenues

Our average total company realized natural gas production sales price, including the realized impact of derivative instruments, was $7.51 per Mcf for the three months ended March 31, 2009 compared to $7.92 per Mcf for the comparable period of the prior year. These prices include the realized impact of derivative instrument settlements, which increased the price by $3.34 per Mcf in 2009 and by $0.03 per Mcf in 2008. The following table excludes the unrealized gain from the change in fair value of our basis swaps of $0.9 million, which has been included within Natural Gas Production Revenues in the Condensed Consolidated Statement of Operations for the quarter ended March 31, 2009. There was no revenue impact from the unrealized change in natural gas derivative fair value for the three months ended March 31, 2008.

	Three Months Ended March 31,		Variance	
	2009	**2008**	**Amount**	**Percent**
Natural Gas Production *(Mmcf)*				
East	**7,280**	6,000	1,280	21%
Gulf Coast	**10,363**	7,405	2,958	40%
West	**6,208**	6,366	(158)	(2%)
Canada	**604**	1,246	(642)	(52%)
Total Company	**24,455**	21,017	3,438	16%
Natural Gas Production Sales Price *($/Mcf)*				
East	**$ 8.34**	$ 8.28	$ 0.06	1%
Gulf Coast	**$ 8.34**	$ 8.30	$ 0.04	
West	**$ 5.54**	$ 7.26	$ (1.72)	(24%)
Canada	**$ 3.51**	$ 7.38	$ (3.87)	(52%)
Total Company	**$ 7.51**	$ 7.92	$ (0.41)	(5%)
Natural Gas Production Revenue *(In thousands)*				
East	**$ 60,705**	$ 49,709	$ 10,996	22%
Gulf Coast	**86,372**	61,437	24,935	41%
West	**34,382**	46,220	(11,838)	(26%)
Canada	**2,122**	9,193	(7,071)	(77%)
Total Company	**$ 183,581**	$ 166,559	$ 17,022	10%
Price Variance Impact on Natural Gas Production Revenue *(In thousands)*				
East	**$ 465**			
Gulf Coast	**396**			
West	**(10,688)**			
Canada	**(2,337)**			
Total Company	**$ (12,164)**			
Volume Variance Impact on Natural Gas Production Revenue *(In thousands)*				
East	**$ 10,531**			
Gulf Coast	**24,539**			
West	**(1,150)**			
Canada	**(4,734)**			
Total Company	**$ 29,186**			

The increase in Natural Gas Production Revenue of $17.0 million, excluding the impact of the unrealized gain on natural gas basis swaps, is due to increases in natural gas production in the Gulf Coast region due to the east Texas property acquisition in the second half of 2008 and

increased drilling in the County Line field, as well as an increase in the East region associated with an increase in the drilling program and initiation of production in Susquehanna, Pennsylvania. Partially offsetting these production increases was a 52% decrease in Canada production due to reduced drilling activity and natural decline, and a slight decrease in production in the West due to natural decline. In addition, overall natural gas realized prices decreased by approximately five percent largely as a result of decreased realized prices in Canada and in the West.

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Brokered Natural Gas Revenue and Cost

	Three Months Ended March 31,		Variance	
	2009	**2008**	**Amount**	**Percent**
Sales Price *($/Mcf)*	**$ 9.08**	$ 9.49	$ (0.41)	(4%)
Volume Brokered *(Mmcf)*	**x 3,675**	x 3,753	(78)	(2%)
Brokered Natural Gas Revenues *(In thousands)*	**$ 33,381**	$ 35,620		
Purchase Price *($/Mcf)*	**$ 8.09**	$ 8.07	$ 0.02	
Volume Brokered *(Mmcf)*	**x 3,675**	x 3,753	(78)	(2%)
Brokered Natural Gas Cost *(In thousands)*	**$ 29,749**	$ 30,290		
Brokered Natural Gas Margin *(In thousands)*	**$ 3,632**	$ 5,330	$ (1,698)	(32%)

(In thousands)	
Sales Price Variance Impact on Revenue	**$ (1,514)**
Volume Variance Impact on Revenue	**(740)**
	$ (2,254)

(In thousands)	
Purchase Price Variance Impact on Purchases	**$ (73)**
Volume Variance Impact on Purchases	**629**
	$ 556

The decreased brokered natural gas margin of $1.7 million is a result of a decrease in sales price and volumes brokered as well as a slight increase in purchase price.

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Crude Oil and Condensate Revenues

Our average total company realized crude oil sales price, including the realized impact of derivative instruments, was $75.25 per Bbl for the first quarter of 2009 compared to $86.55 per Bbl for the first quarter of 2008. These prices include the realized impact of derivative instrument settlements, which increased the price by $39.07 in 2009 and decreased the price by $8.60 per Bbl in 2008. There was no revenue impact from the unrealized change in crude oil and condensate derivative fair value for the three months ended March 31, 2009 and 2008.

	Three Months Ended March 31,		Variance	
	2009	**2008**	**Amount**	**Percent**
Crude Oil Production *(Mbbl)*				
East	**4**	6	(2)	(33%)
Gulf Coast	**148**	144	4	3%
West	**33**	34	(1)	(3%)
Canada	**4**	6	(2)	(33%)
Total Company	**189**	190	(1)	(1%)
Crude Oil Sales Price *($/Bbl)*				
East	**$ 37.25**	$ 90.04	$ (52.79)	(59%)
Gulf Coast	**$ 87.02**	$ 84.58	$ 2.44	3%
West	**$ 32.22**	$ 95.66	$ (63.44)	(66%)
Canada	**$ 32.01**	$ 79.38	$ (47.37)	(60%)
Total Company	**$ 75.25**	$ 86.55	$ (11.30)	(13%)
Crude Oil Revenue *(In thousands)*				
East	**$ 141**	$ 543	$ (402)	(74%)
Gulf Coast	**12,903**	12,201	702	6%
West	**1,066**	3,243	(2,177)	(67%)
Canada	**132**	500	(368)	(74%)
Total Company	**$ 14,242**	$ 16,487	$ (2,245)	(14%)
Price Variance Impact on Crude Oil Revenue *(In thousands)*				
East	**$ (199)**			
Gulf Coast	**362**			
West	**(2,100)**			
Canada	**(194)**			
Total Company	**$ (2,131)**			
Volume Variance Impact on Crude Oil Revenue *(In thousands)*				
East	**$ (203)**			
Gulf Coast	**340**			
West	**(77)**			
Canada	**(174)**			
Total Company	**$ (114)**			

The decrease in realized crude oil prices and a slight decrease in crude oil production resulted in a net revenue decrease of $2.2 million. Realized crude oil prices and production declined in all regions except for the Gulf Coast.

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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 March 31,			
	2009		2008	
(In thousands)	**Realized**	**Unrealized**	**Realized**	**Unrealized**
Operating Revenues Increase / (Decrease) to Revenue				
Cash Flow Hedges				
Natural Gas Production	**$ 81,710**	**$**	$ 612	$
Crude Oil	**7,384**		(1,634)	
Total Cash Flow Hedges	**89,094**		(1,022)	
Other Derivative Financial Instruments				
Natural Gas Basis Swaps		**941**		
Total Other Derivative Financial Instruments		**941**		
Total Cash Flow Hedges and Other Derivative Financial Instruments	**$ 89,094**	**$ 941**	$ (1,022)	$

We are exposed to market risk on derivative instruments to the extent of changes in market prices of natural gas and 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 JPMorgan Chase, Morgan Stanley, BNP Paribas, Goldman Sachs, and Bank of Montreal.

Operating Expenses

Total costs and expenses from operations increased by $13.2 million in the first quarter of 2009 compared to the same period of 2008. The primary reasons for this fluctuation are as follows:

Depreciation, Depletion and Amortization increased by $14.3 million from the first quarter of 2008 compared to the first quarter of 2009. This is primarily due to the impact on the DD&A rate of higher capital costs and higher natural gas production volumes, including the east Texas acquisition in August 2008.

General and Administrative expenses decreased by $10.5 million from the first quarter of 2008 compared to the first quarter of 2009. This is primarily due to decreased stock compensation expense largely related to our performance share awards ($7.7 million) as well as a reduction in supplemental employee compensation of $4.5 million from the prior year first quarter.

Direct Operations expenses increased by $8.0 million from the first quarter of 2008 compared with the first quarter of 2009 primarily due to higher personnel and labor expenses, compressor, workover, treating and disposal costs and outside operated properties expenses, partially offset by lower insurance costs.

Impairment of Unproved Properties increased by $4.5 million from the first quarter of 2008 compared to the first quarter of 2009, primarily due to increased lease acquisition costs incurred in several exploratory and developmental areas in the East and in east Texas, including the Minden area.

Taxes Other Than Income decreased by $4.0 million in the first quarter of 2009 compared with the first quarter of 2008 due to lower production taxes as a result of lower average natural gas and crude oil prices, partially offset by higher ad valorem taxes.

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Exploration expense increased by $1.4 million from the first quarter of 2008 compared to the first quarter of 2009 primarily due to increased geological and geophysical costs.

Interest Expense, Net

Interest expense, net increased by $8.2 million in the first quarter of 2009 compared to the first quarter of 2008 primarily due to increased interest expense related to the debt we issued in our July and December 2008 private placements. Weighted-average borrowings under our credit facility based on daily balances were approximately $211 million during the first three months of 2009 compared to approximately $157 million during the first three months of 2008. The weighted-average effective interest rate on the credit facility decreased to approximately 4.0% during the first quarter of 2009 compared to approximately 6.0% during the first quarter of 2008.

Income Tax Expense

Income tax expense increased by $4.0 million due to a comparable increase in our pre-tax income. The effective tax rates for the first quarter of 2009 and 2008 were 37.1% and 34.4%, respectively. The effective tax rate was lower in the first quarter of 2008 primarily due to a benefit recorded as a result of a reduction in our overall state income tax liability.

Forward-Looking Information

The statements regarding future financial performance and results, market prices and the other statements which are not historical facts contained in this report are forward-looking statements. The words expect, project, estimate, believe, anticipate, intend, budget, plan, predict and similar expressions are also intended to identify forward-looking statements. Such statements involve risks and uncertainties, including, but not limited to, market factors, market prices (including regional basis differentials) of natural gas and 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 oil and natural gas prices. Realized prices are mainly driven by worldwide prices for oil and spot market prices for North American natural gas production. Commodity prices are volatile and unpredictable.

The debt and equity markets have recently experienced unfavorable conditions, which may affect our ability to access those markets. As a result of the volatility and disruption in the capital markets and our increased level of borrowings, we may experience increased costs associated with future borrowings and debt issuances. At this time, we do not believe our liquidity has been materially affected by the recent market events. We will continue to monitor events and circumstances surrounding each of our lenders in our revolving credit facility.

Derivative Instruments and Hedging Activity

Our hedging strategy is designed to reduce the risk of price volatility for our production in the natural gas and crude oil markets. A hedging committee that consists of members of senior management oversees our hedging activity. Our hedging arrangements apply to only a portion of our production and provide only partial price protection. These hedging arrangements limit the benefit to us of increases in 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 March 31, 2009, we had 26 cash flow hedges open: 14 natural gas price collar arrangements, 10 natural gas price swap arrangements and two crude oil price swap arrangements. During the first quarter of 2009, we entered into six new derivative contracts covering anticipated natural gas production for 2012. These natural gas basis swaps did not qualify for hedge accounting under SFAS No. 133. These natural gas basis swaps mitigate the risk associated with basis differentials that may expand or increase over time, thus reducing the exposure and risk of basis fluctuations.

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As of March 31, 2009, we had the following outstanding commodity derivatives:

Commodity	Derivative Type	Weighted-Average Contract Price[1]		Volume		Contract Period	Net Unrealized Gain
Hedging Instruments							
Natural Gas	Swap	$12.18	per Mcf	16,079	Mmcf	2009	$ 91,881
Natural Gas	Swap	$11.43	per Mcf	19,295	Mmcf	2010	96,901
Natural Gas	Collar	$12.39 / $9.40	per Mcf	47,253	Mmcf	2009	178,957
Crude Oil	Swap	$125.25	per Bbl	365	Mbbl	2009	21,603
Crude Oil	Swap	$125.00	per Bbl	365	Mbbl	2010	22,308
							$ 411,650
Other Derivative Instruments							
Natural Gas	Basis Swap	$(0.27)	per Mcf	16,123	Mmcf	2012	944
							$ 412,594

(1) For collar derivatives, the amounts in this column represent the ceiling and floor prices.

The amounts set forth under the net unrealized gain column in the tables above represent our total unrealized gain position at March 31, 2009 and do not include the impact of nonperformance risk. Also impacting the total unrealized net gain (reflecting the net receivable position) in accumulated other comprehensive income / (loss) in the Condensed Consolidated Balance Sheet is a reduction of $7.4 million related to our assessment of our counterparties nonperformance risk. This risk was primarily evaluated by reviewing credit default swap spreads for the various financial institutions in which we have derivative transactions.

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

During the first quarter of 2009, natural gas price swaps covered 3,964 Mmcf, or 16%, of our first quarter of 2009 gas production at an average price of $12.18 per Mcf.

We had one crude oil price swap covering 90 Mbbl, or 48%, of our first three months of 2009 oil production at a price of $125.25 per Bbl.

From time to time, we enter into natural gas and crude oil collar agreements with counterparties to hedge price risk associated with a portion of our production. These cash flow hedges are not held for trading purposes. Under the collar arrangements, 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. During the first three months of 2009, natural gas price collars covered 11,652 Mmcf, or 48%, of our first quarter of 2009 gas production, with a weighted-average floor of $9.40 per Mcf and a weighted-average ceiling of $12.39 per Mcf.

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.

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ITEM 4. Controls and Procedures

As of the end of the current reported period covered by this report, the Company carried out an evaluation, under the supervision and with the participation of the Company s management, including the Company s Chief Executive Officer and Chief Financial Officer, of the effectiveness of the design and operation of the Company s disclosure controls and procedures pursuant to Rules 13a-15 and 15d-15 of the Securities Exchange Act of 1934 (the Exchange Act). Based upon that evaluation, the Chief Executive Officer and Chief Financial Officer concluded that the Company s disclosure controls and procedures are effective, in all material respects, 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 first quarter of 2009 that have materially affected, or are reasonably likely to materially affect, the Company s internal control over financial reporting.

PART II. OTHER INFORMATION

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, 2008.

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

Issuer Purchases of Equity Securities

The Board of Directors has authorized a share repurchase program under which the Company may purchase shares of common stock in the open market or in negotiated transactions. There is no expiration date associated with the authorization. During the three months ended March 31, 2009, 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 March 31, 2009 was 4,795,300.

ITEM 6. Exhibits

4.1	Credit Agreement, dated as of April 24, 2009, among the Company, JPMorgan Chase Bank, N.A., as Administrative Agent, Banc of America Securities LLC, as Syndication Agent, Bank of Montreal, as Documentation Agent, and the Lenders party thereto (Form 8-K for April 24, 2009).
15.1	Awareness letter of PricewaterhouseCoopers LLP
31.1	302 Certification Chairman, President and Chief Executive Officer
31.2	302 Certification Vice President and Chief Financial Officer
32.1	906 Certification

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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)

April 30, 2009

By: /s/ Dan O. Dinges
Dan O. Dinges
Chairman, President and

Chief Executive Officer

(Principal Executive Officer)

April 30, 2009

By: /s/ Scott C. Schroeder
Scott C. Schroeder
Vice President and Chief Financial Officer

(Principal Financial Officer)

April 30, 2009

By: /s/ Henry C. Smyth
Henry C. Smyth
Vice President, Controller and Treasurer

(Principal Accounting Officer)