CABOT OIL & GAS CORP
Form 10-Q
October 29, 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 September 30, 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)**

Three Memorial City Plaza

840 Gessner Road, Suite 1400, Houston, Texas 77024

(Address of principal executive offices including ZIP Code)

(281) 589-4600

(Registrant s telephone number, including area code)

1200 Enclave Parkway, Houston, Texas 77077

(Former address, if changed since last report)

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

Yes x No ¨

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

Yes x No ¨

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

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

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

Yes ¨ No **x**

As of October 20, 2009, there were 103,654,113 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 September 30, 2009	Three Months Ended September 30, 2008	Nine Months Ended September 30, 2009	Nine Months Ended September 30, 2008
OPERATING REVENUES				
Natural Gas Production	**$ 177,807**	$ 200,279	**$ 538,542**	$ 569,527
Brokered Natural Gas	**9,032**	23,855	**54,117**	86,663
Crude Oil and Condensate	**19,574**	20,002	**50,026**	55,089
Other	**608**	684	**3,099**	2,046
	207,021	244,820	**645,784**	713,325
OPERATING EXPENSES				
Brokered Natural Gas Cost	**7,786**	20,891	**48,219**	75,321
Direct Operations Field and Pipeline	**23,012**	24,974	**71,564**	65,101
Exploration	**14,395**	6,413	**31,258**	18,764
Depreciation, Depletion and Amortization	**54,886**	48,895	**165,779**	132,893
Impairment of Unproved Properties	**7,151**	8,512	**23,188**	19,182
General and Administrative	**14,921**	(209)	**49,103**	60,841
Taxes Other Than Income	**10,719**	20,627	**34,531**	56,749
	132,870	130,103	**423,642**	428,851
Gain / (Loss) on Sale of Assets	**572**		**(3,283)**	401
INCOME FROM OPERATIONS	**74,723**	114,717	**218,859**	284,875
Interest Expense and Other	**14,857**	10,486	**44,129**	22,684
Income Before Income Taxes	**59,866**	104,231	**174,730**	262,191
Income Tax Expense	**20,969**	37,241	**62,751**	94,601
NET INCOME	**$ 38,897**	$ 66,990	**$ 111,979**	$ 167,590
Basic Earnings Per Share	**$ 0.38**	$ 0.65	**$ 1.08**	$ 1.68
Diluted Earnings Per Share	**$ 0.37**	$ 0.64	**$ 1.07**	$ 1.66
Weighted-Average Common Shares Outstanding	**103,647**	103,351	**103,603**	99,858
Diluted Common Shares (Note 5)	**104,917**	104,495	**104,583**	100,901

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)	**September 30, 2009**	**December 31, 2008**
ASSETS		
Current Assets		
Cash and Cash Equivalents	**$ 35,670**	$ 28,101
Accounts Receivable, Net (Note 3)	**52,613**	109,087
Income Taxes Receivable	**33,103**	526
Inventories (Note 3)	**36,769**	45,677
Current Derivative Contracts (Note 7)	**166,787**	264,660
Other Current Assets (Note 3)	**10,065**	12,500
Total Current Assets	**335,007**	460,551
Properties and Equipment, Net (Successful Efforts Method) (Note 2)	**3,184,305**	3,135,828
Long-Term Derivative Contracts (Note 7)	**24,349**	90,542
Investment in Equity Securities (Note 2)	**20,636**	
Other Assets (Note 3)	**24,757**	14,743
	$ 3,589,054	$ 3,701,664
LIABILITIES AND STOCKHOLDERS EQUITY		
Current Liabilities		
Accounts Payable (Note 3)	**$ 115,940**	$ 222,985
Current Portion of Long-Term Debt (Note 4)	**20,000**	35,857
Deferred Income Taxes	**58,862**	63,985
Income Taxes Payable	**6,649**	5,535
Accrued Liabilities (Note 3)	**45,721**	50,551
Total Current Liabilities	**247,172**	378,913
Long-Term Liability for Pension and Postretirement Benefits (Note 9)	**49,755**	54,714
Long-Term Debt (Note 4)	**790,000**	831,143
Deferred Income Taxes	**623,946**	599,106
Other Liabilities (Note 3)	**54,367**	47,226
Total Liabilities	**1,765,240**	1,911,102
Commitments and Contingencies (Note 6)		
Stockholders Equity		
Common Stock:		
Authorized 240,000,000 Shares of $0.10 Par Value in 2009 and 120,000,000 Shares of $0.10 Par Value in 2008		
Issued 103,856,313 Shares and 103,561,268 Shares in 2009 and 2008, respectively	**10,386**	10,356
Additional Paid-in Capital	**699,971**	675,568
Retained Earnings	**1,024,217**	921,561
Accumulated Other Comprehensive Income (Note 8)	**92,589**	186,426
Less Treasury Stock, at Cost:		
202,200 Shares in 2009 and 2008, respectively	**(3,349)**	(3,349)
Total Stockholders Equity	**1,823,814**	1,790,562
	$ 3,589,054	$ 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)

	Nine Months Ended September 30,	
(In thousands)	**2009**	**2008**
CASH FLOWS FROM OPERATING ACTIVITIES		
Net Income	**$ 111,979**	$ 167,590
Adjustments to Reconcile Net Income to Cash Provided by Operating Activities:		
Depreciation, Depletion and Amortization	**165,779**	132,893
Impairment of Unproved Properties	**23,188**	19,182
Deferred Income Tax Expense	**74,773**	96,459
(Gain) / Loss on Sale of Assets	**3,283**	(401)
Exploration Expense	**31,258**	18,764
Unrealized Loss on Derivatives	**418**	1,649
Stock-Based Compensation Expense and Other	**19,894**	10,371
Changes in Assets and Liabilities:		
Accounts Receivable, Net	**56,474**	(9,869)
Income Taxes Receivable	**(19,406)**	1,650
Inventories	**8,908**	(24,799)
Other Current Assets	**2,435**	7,420
Other Assets	**(173)**	5,694
Accounts Payable and Accrued Liabilities	**(49,097)**	11,054
Income Taxes Payable	**1,572**	(942)
Other Liabilities	**(1,070)**	(976)
Stock-Based Compensation Tax Benefit	**(13,085)**	(11,011)
Net Cash Provided by Operating Activities	**417,130**	424,728
CASH FLOWS FROM INVESTING ACTIVITIES		
Capital Expenditures	**(394,525)**	(558,931)
Acquisitions	**(394)**	(605,408)
Proceeds from Sale of Assets	**80,180**	1,150
Exploration Expense	**(31,258)**	(18,764)
Net Cash Used in Investing Activities	**(345,997)**	(1,181,953)
CASH FLOWS FROM FINANCING ACTIVITIES		
Borrowings from Debt	**90,000**	735,000
Repayments of Debt	**(147,000)**	(265,000)
Net Proceeds from Sale of Common Stock	**83**	316,229
Stock-Based Compensation Tax Benefit	**13,085**	11,011
Dividends Paid	**(9,323)**	(8,973)
Capitalized Debt Issuance Costs	**(10,409)**	(2,166)
Net Cash (Used in) / Provided by Financing Activities	**(63,564)**	786,101
Net Increase in Cash and Cash Equivalents	**7,569**	28,876
Cash and Cash Equivalents, Beginning of Period	**28,101**	18,498
Cash and Cash Equivalents, End of Period	**$ 35,670**	$ 47,374

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. Subsequent events have been evaluated through October 29, 2009, which is also the date that the financial statements were issued.

Certain prior year amounts have been reclassified to reflect changes in presenting the geographic areas for which the Company conducts its operations. These areas consist of the North (comprised of the East and Rocky Mountain areas), South (comprised of the Gulf Coast and Anadarko areas) and Canada. In previous periods, the Company presented the geographic areas as East, Gulf Coast, West and Canada.

With respect to the unaudited financial information of the Company as of September 30, 2009 and for the three and nine month periods ended September 30, 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 October 29, 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 July 2009, the Financial Accounting Standards Board (FASB) issued Accounting Standards Codification (ASC) 105, Generally Accepted Accounting Principles, establishing the accounting standards codification and the hierarchy of generally accepted accounting principles (GAAP) as the sole source of authoritative non-governmental U.S. GAAP. The Codification was not intended to change U.S. GAAP; however, references to various accounting pronouncements and literature will now differ from what was previously being used in practice. Authoritative literature is now referenced by topic rather than by type of standard. As of July 1, 2009, the FASB no longer issues Statements, Interpretations, Staff Positions or EITF Abstracts. The FASB now communicates new accounting standards by issuing an Accounting Standards Update (ASU). All guidance in the Codification has an equal level of authority. ASC 105 is effective for financial statements that cover interim and annual periods ending after September 15, 2009, and supersedes all accounting standards in U.S. GAAP, aside from those issued by the SEC. There was no impact on the Company s financial position, results of operations or cash flows as a result of the Codification.

In February 2008, the FASB issued an amendment to ASC 820, Fair Value Measurements and Disclosures, 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 ASC 820. Effective January 1, 2009, the Company applied these amendments of ASC 820 discussed above and there was no 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 amendments that the FASB made to ASC 260, Earnings Per Share, regarding determining whether instruments granted in share-based payment transactions are participating securities. The adoption of these amendments 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.

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In March 2008, the FASB amended the disclosure requirements prescribed in ASC 815, Derivatives and Hedging. The Company adopted these amendments 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.

In April 2009, the FASB amended guidance in ASC 820 regarding determining fair value when the volume and level of activity for an asset or liability has significantly decreased and identifying transactions that are not orderly. 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 ASC 820 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. These amendments became effective for interim and annual reporting periods ending after June 15, 2009 and did not have a material impact on the Company s financial position, results of operations or cash flows.

In April 2009, the FASB amended ASC 825, 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. These amendments became effective for interim reporting periods ending after June 15, 2009, and the Company has provided interim disclosures regarding the fair value of debt instruments in Note 4 of the Notes to the Condensed Consolidated Financial Statements. Comparative disclosures are only required for periods ending after the initial adoption. There was no material impact on the Company s financial position, results of operations or cash flows as a result of the adoption.

In April 2009, the FASB amended the other-than-temporary impairment guidance for debt securities in ASC 320, Investments-Debt and Equity 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. There were no amendments made to the recognition and measurement guidance for equity securities, but a new method of recognizing and reporting for debt securities was established. Disclosure requirements for impaired debt and equity securities have been expanded significantly and are now required quarterly, as well as annually. These amendments became effective for interim and annual reporting periods ending after June 15, 2009 and did not have a material impact on the Company s financial position, results of operations or cash flows. Comparative disclosures are only required for periods ending after the initial adoption.

In June 2009, the FASB amended ASC 855, Subsequent Events, to require entities to disclose the date through which they have evaluated subsequent events and whether the date corresponds with the release of their financial statements. In addition, a new concept of financial statements being available to be issued was introduced. These amendments became effective for interim and annual periods ending after June 15, 2009 and did not have any impact on the Company s financial position, results of operations or cash flows.

In August 2009, the FASB issued Accounting Standards Update (ASU) No. 2009-05, Fair Value Measurement and Disclosures: Measuring Liabilities at Fair Value, which provides clarification on measuring liabilities at fair value when a quoted price in an active market is not available. ASU No. 2009-05 specifies that in cases where a quoted price in an active market is not available, a valuation technique should be applied that uses either the quote of the liability when traded as an asset, the quoted prices for similar liabilities or similar liabilities when traded as assets, or another valuation technique consistent with existing fair value measurement guidance. Valuation methods discussed include using an income approach, such as a present value technique, or a market approach based on the amount at the measurement date that the reporting entity would pay to transfer the identical liability or would receive to enter into the identical liability. Entities are not required to include a separate input or adjustment to other inputs relating to the existence of a restriction that prevents the transfer of the liability. ASU No. 2009-05 is codified in ASC 820-10 and is effective for the first reporting period (including interim periods) beginning after issuance. There was no impact on the Company s financial position, results of operations or cash flows as a result of the adoption of ASU No. 2009-05.

Recently Issued Accounting Pronouncements

In June 2009, the FASB issued Statement of Financial Accounting Standards (SFAS) No. 166, Accounting for Transfers of Financial Assets. SFAS No. 166 has not yet been codified, but revises ASC 860, Transfers and Servicing, and will require entities to provide more information about sales of securitized financial assets and similar transactions, particularly if the seller retains some risk to the assets. SFAS No. 166 will be effective at the beginning of the first fiscal year beginning after November 15, 2009. As the Company does not anticipate having any of these types of transactions in the near future, SFAS No. 166 is not expected to have any 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. The Company is currently evaluating what impact Release No. 33-8995 may have on its financial position, results of operations or cash flows.

In December 2008, the FASB issued an amendment to ASC 715-20, Compensation Retirement Benefits Defined Benefit Plans General, which requires enhanced disclosures regarding Company benefit plans. Disclosure regarding plan assets should include discussion about how investment allocation decisions are made, the major categories of plan assets, the inputs and valuation techniques used to measure plan assets and significant concentrations of risk within plan assets. These amendments to ASC 715-20 are effective for fiscal years ending after December 15, 2009, and earlier application is permitted. Prior year periods presented for comparative purposes are not required to comply. The Company does not believe that these amendments to ASC 715-20 will have a material impact on its financial position, results of operations or cash flows.

2. PROPERTIES AND EQUIPMENT, NET

Properties and equipment, net are comprised of the following:

(In thousands)	**September 30, 2009**	**December 31, 2008**
Unproved Oil and Gas Properties	**$ 301,992**	$ 315,782
Proved Oil and Gas Properties	**4,010,954**	3,813,014
Gathering and Pipeline Systems	**277,120**	274,192
Land, Building and Other Equipment	**72,372**	68,606
	4,662,438	4,471,594
Accumulated Depreciation, Depletion and Amortization	**(1,478,133)**	(1,335,766)
	$ 3,184,305	$ 3,135,828

At September 30, 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.

In April 2009, the Company sold its Canadian properties to a private Canadian company. Total consideration received from the sale was $84.4 million, consisting of $64.3 million in cash and $20.1 million in common stock of the Canadian company (included on the Condensed Consolidated Balance Sheet as Investment in Equity Securities at September 30, 2009). The common stock investment is being accounted for using the cost method. The total net book value of the Canadian properties sold was $95.0 million. At December 31, 2008, the Company recorded 40.4 Bcfe of proved reserves (two percent of total proved reserves) related to these properties.

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The Company recognized a $3.9 million aggregate loss on sale of assets in the first nine months of 2009. During 2009, the Company recorded a $10.5 million (net of taxes of $6.1 million) loss on sale of assets, primarily due to the sale of the Canadian properties described above. In addition, the Company recognized a $12.7 million gain on sale of assets during the first nine months of 2009 primarily related to the first quarter 2009 sale of Thornwood properties in the East. Cash proceeds of $11.4 million were received from the sale of the Thornwood properties.

3. ADDITIONAL BALANCE SHEET INFORMATION

Certain balance sheet amounts are comprised of the following:

(In thousands)	**September 30, 2009**	**December 31, 2008**
ACCOUNTS RECEIVABLE, NET		
Trade Accounts	**$ 44,987**	$ 94,164
Joint Interest Accounts	**9,522**	16,454
Other Accounts	**1,813**	1,987
	56,322	112,605
Allowance for Doubtful Accounts	**(3,709)**	(3,518)
	$ 52,613	$ 109,087
INVENTORIES		
Natural Gas in Storage	**$ 20,022**	$ 27,478
Tubular Goods and Well Equipment	**16,298**	16,439
Pipeline Imbalances	**449**	1,760
	$ 36,769	$ 45,677
OTHER CURRENT ASSETS		
Drilling Advances	**$ 2,773**	$ 4,869
Prepaid Balances	**7,292**	7,631
	$ 10,065	$ 12,500
OTHER ASSETS		
Rabbi Trust Deferred Compensation Plan	**$ 10,644**	$ 8,651
Deferred Charges for Credit Agreements	**12,694**	4,847
Other Accounts	**1,419**	1,245
	$ 24,757	$ 14,743
ACCOUNTS PAYABLE		
Trade Accounts	**$ 15,078**	$ 44,088
Natural Gas Purchases	**4,427**	5,346
Royalty and Other Owners	**31,409**	42,349
Capital Costs	**53,425**	117,029
Taxes Other Than Income	**3,403**	5,617
Drilling Advances	**1,089**	1,289
Wellhead Gas Imbalances	**4,096**	3,354
Other Accounts	**3,013**	3,913
	$ 115,940	$ 222,985

ACCRUED LIABILITIES				
Employee Benefits	**$**	**7,025**	$	10,807
Current Liability for Pension Benefits		**245**		245
Current Liability for Postretirement Benefits		**642**		642
Taxes Other Than Income		**23,893**		16,582
Interest Payable		**11,665**		20,684
Other Accounts		**2,251**		1,591
	$	**45,721**	$	50,551
OTHER LIABILITIES				
Rabbi Trust Deferred Compensation Plan	**$**	**18,824**	$	14,531
Accrued Plugging and Abandonment Liability		**29,229**		27,978
Derivative Contracts		**757**		-
Other Accounts		**5,557**		4,717
	$	**54,367**	$	47,226

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4. LONG-TERM DEBT

The Company s debt consisted of the following:

(In thousands)	**September 30, 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	**128,000**	185,000
Current Maturities		
7.19% Notes	**(20,000)**	(20,000)
Credit Facility		(15,857)
Total Current Maturities	**(20,000)**	(35,857)
Long-Term Debt, excluding Current Maturities	**$ 790,000**	$ 831,143

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

In conjunction with entering into the new credit facility, the Company incurred $10.4 million of debt issuance costs which were capitalized and will be amortized over the term of the credit facility. Additionally, $1.5 million in unamortized costs associated with the prior credit facility will be amortized over the term of the new credit facility in accordance with ASC 470-50, Debt-Modifications and Extinguishments.

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 in connection with scheduled redetermination or due to a termination of hedge positions, the Company has a period of six months to reduce its outstanding debt in equal monthly installments 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 under the credit facility and the Company s senior notes is greater than 25%, greater than 50%, greater than 75% or greater than 90% of the Borrowing Base, as shown below:

			Debt Percentage		
	<25%	**³ 25% <50%**	**³ 50% <75%**	**³ 75% <90%**	**³ 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%.

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, as defined in the agreement, 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.

At September 30, 2009, the Company had $128 million of borrowings outstanding under its revolving credit facility at a weighted-average interest rate of 3.7%.

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 amendments that the FASB made to ASC 260, Earnings Per Share, regarding determining whether instruments granted in share-based payment transactions are participating securities. Under these amendments, 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. These amendments 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, basic earnings per share (EPS) is required to be computed using the two-class method prescribed in ASC 260. 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. ASC 260 defines participating securities as securities that may participate in dividends with common stocks according to a predetermined formula. ASC 260 provides that its provisions under the amendments discussed above 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.

The following is a calculation of basic and diluted weighted-average shares outstanding for the three and nine months ended September 30, 2009 and 2008:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2009	**2008**	**2009**	**2008**
Weighted-Average Shares Basic	**103,647,016**	103,351,147	**103,603,085**	99,857,606
Dilution Effect of Stock Options and Awards at End of Period	**1,269,683**	1,144,096	**980,043**	1,043,650
Weighted-Average Shares Diluted	**104,916,699**	104,495,243	**104,583,128**	100,901,256
Weighted-Average Stock Awards and Shares Excluded from Diluted Earnings per Share due to the Anti-Dilutive Effect	**213,480**		**233,489**	149,524

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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 $1.0 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 the North region. 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. The agreements that the Company previously had in place on pipeline systems in Canada were transferred in April 2009 to the buyer in connection with the sale of our Canadian properties (discussed in Note 2).

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 September 30, 2009, obligations under firm gas transportation agreements were $92.2 million. For further information on these future obligations, please refer to Note 7 of the Notes to the Consolidated Financial Statements in the Form 10-K.

Drilling Rig Commitments

In the Form 10-K, the Company disclosed that it had total commitments of $44.3 million on eight drilling rigs in the South region that are under contracts with initial terms of greater than one year. The Company entered into a new drilling rig commitment of approximately $8 million in the first nine months of 2009. The total commitment for nine drilling rigs for the years ending December 31, 2009 and 2010 was $53.8 million ($47.4 million for 2009 and $6.4 million for 2010). As of September 30, 2009, outstanding commitments for drilling rigs for the remainder of 2009 and for 2010 total $12.6 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 an amendment to ASC 820, Fair Value Measurements and Disclosures, 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 ASC 820. Effective January 1, 2009, the Company applied these amendments of ASC 820 discussed above and there was no 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 long-lived assets, asset retirement obligations and assets acquired and liabilities assumed in a business combination, if any.

ASC 820 established a formal framework for measuring fair values of assets and liabilities in financial statements that are already required by GAAP to be measured at fair value. As defined in ASC 820, fair value is the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date (exit price). The transaction is based on a hypothetical transaction in the principal or most advantageous market considered from the perspective of the market participant that holds the asset or owes the liability.

The Company utilizes market data or assumptions that market participants who are independent, knowledgeable and willing and able to transact would use in pricing the asset or liability, including assumptions about risk and the risks inherent in the inputs to the valuation technique. These inputs can be readily observable, market corroborated or generally unobservable. The Company attempts to utilize valuation techniques that maximize the use of observable inputs and minimize the use of unobservable inputs. The Company is able to classify fair value balances based on the observability of those inputs. ASC 820 establishes 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 ASC 820, refer to Note 11 of the Notes to the Consolidated Financial Statements in the Form 10-K.

In accordance with ASC 820, 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 September 30, 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 September 30, 2009**
Assets				
Rabbi Trust Deferred Compensation Plan	$ 10,644	$	$	**$ 10,644**
Derivative Contracts			191,136	**191,136**
Total Assets	$ 10,644	$	$ 191,136	**$ 201,780**
Liabilities				
Rabbi Trust Deferred Compensation Plan	$ 18,824	$	$	**$ 18,824**
Derivative Contracts			757	**757**
Total Liabilities	$ 18,824	$	$ 757	**$ 19,581**

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 ASC 820. 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.

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The following table sets forth a reconciliation of changes for the three and nine month periods ended September 30, 2009 and 2008 in the fair value of financial assets and liabilities classified as Level 3 in the fair value hierarchy:

	Three Months Ended September 30,		Nine Months Ended September 30,	
(In thousands)	**2009**	**2008**	**2009**	**2008**
Balance at beginning of period	**$ 297,388**[(1)]	$ (282,771)[(2)]	**$ 355,202**[(3)]	$ 7,272[(4)]
Total Gains or (Losses) (Realized or Unrealized):				
Included in Earnings[(5)]	**106,795**	(8,799)	**303,632**	(38,147)
Included in Other Comprehensive Income	**(105,776)**	472,268	**(164,405)**	185,133
Purchases, Issuances and Settlements	**(108,028)**	10,058	**(304,050)**	36,498
Transfers In and/or Out of Level 3				
Balance at end of period	**$ 190,379**	$ 190,756	**$ 190,379**	$ 190,756

(1) Balance was entirely comprised of derivative assets.

(2) Balance was entirely comprised of derivative liabilities.

(3) Balance was entirely comprised of derivative assets.

(4) Balance was comprised of derivative assets of $12.7 million and derivative liabilities of $5.4 million.

(5) A loss of $1.2 million and $0.4 million for the three and nine months ended September 30, 2009, respectively, was unrealized and included in Natural Gas Production Revenues in the Statement of Operations. A gain of $1.3 million and a loss of $1.6 million for the three and nine months ended September 30, 2008, respectively, was unrealized and included in Natural Gas Production Revenues in the Statement of Operations.

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 interest rates, such as a LIBOR curve for a similar length of time as the derivative contract term. These estimates are compared to multiple quotes obtained from counterparties for reasonableness. The Company measured the nonperformance risk of its counterparties by reviewing credit default swap spreads for the various financial institutions in which it has derivative transactions. The resulting reduction to the net receivable derivative contract position was $0.5 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.

Fair Market Value of Financial Instruments

The estimated fair value of financial instruments is the amount at which the instrument could be exchanged currently between willing parties. The carrying amounts reported in the Condensed Consolidated Balance Sheet for cash and cash equivalents, accounts receivable and accounts payable approximate fair value. The fair value of long-term debt is the estimated cost to acquire the debt, including a credit spread for the difference between the issue rate and the period end market rate. The credit spread is the Company s default or repayment risk. The credit spread (premium or discount) is determined by comparing the Company s fixed-rate notes to new issuances (secured and unsecured) and secondary trades of similar size and credit statistics for both public and private debt. The fair value of all of the notes, excluding the credit facility, are based on interest rates currently available to the Company. The credit facility approximates fair value because this instrument bears interest at rates based on current market rates.

The Company uses available market data and valuation methodologies to estimate the fair value of debt. This disclosure is presented in accordance with ASC 825-10-50, Financial Instruments-Overall-Disclosures, as well as ASC 820, Fair Value Measurements and Disclosures, and does not impact the Company s financial position, results of operations or cash flows.

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(In thousands)	September 30, 2009 Carrying Amount	September 30, 2009 Estimated Fair Value	December 31, 2008 Carrying Amount	December 31, 2008 Estimated Fair Value
Long-Term Debt	**$ 810,000**	**$ 856,535**	$ 867,000	$ 807,508
Current Maturities	**(20,000)**	**(20,704)**	(35,857)	(35,796)
Long-Term Debt, excluding Current Maturities	**$ 790,000**	**$ 835,831**	$ 831,143	$ 771,712

Derivative Instruments and Hedging Activity

In March 2008, the FASB issued guidance and amended the disclosure requirements prescribed in ASC 815, Derivatives and Hedging. Entities are now required to provide greater transparency about how and why the entity uses derivative instruments, how the instruments and related hedged items are accounted for under ASC 815 and how the instruments and related hedged items affect the financial position, results of operations and cash flows of the entity. The Company adopted these new disclosure requirements 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 September 30, 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 nine months 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 ASC 815. 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 September 30, 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 ASC 815						
Natural Gas	Collar	$12.39 / $9.40	per Mcf	11,910	Mmcf	2009
Natural Gas	Swap	$12.18	per Mcf	4,053	Mmcf	2009
Natural Gas	Swap	$11.43	per Mcf	19,295	Mmcf	2010
Crude Oil	Swap	$125.25	per Bbl	92	Mbbl	2009
Crude Oil	Swap	$125.00	per Bbl	365	Mbbl	2010
Derivatives not qualifying as Hedging Instruments under ASC 815						
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 derivatives not qualifying as hedges, 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 September 30, 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 ASC 815				
Natural Gas Commodity Contracts	Current Derivative Contracts	$ 146,239		$
Natural Gas Commodity Contracts	Long-Term Derivative Contracts	19,560		
Crude Oil Commodity Contracts	Current Derivative Contracts	20,548		
Crude Oil Commodity Contracts	Long-Term Derivative Contracts	4,450		
		$ 190,797		
Derivatives not qualifying as Hedging Instruments under ASC 815				
Natural Gas Commodity Basis Contracts	Long-Term Derivative Contracts	339	Other Liabilities	(757)
		$ 191,136		**$ (757)**

At September 30, 2009, a $190.8 million ($119.8 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 $0.4 million unrealized loss was recorded in the Condensed Consolidated Statement of Operations as a component of Natural Gas Production Revenue for the nine months ended September 30, 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 ASC 815				
Natural Gas Commodity Contracts	$ 165,799	Natural Gas Production Revenues	$ 285,453	N/A
Crude Oil Commodity Contracts	24,998	Crude Oil and Condensate Revenues	18,597	N/A
	$ 190,797		**$ 304,050**	

(In thousands)	**Location of Loss Recognized in Income on Derivative**	**Amount of Loss Recognized in Income on Derivative**
Derivatives not qualifying as Hedging Instruments under ASC 815		

Natural Gas Commodity Contracts	Natural Gas Production Revenues	**$**	**(418)**

Based upon estimates at September 30, 2009, the Company would expect to reclassify from Other Comprehensive Income to the Condensed Consolidated Statement of Operations over the next 12 months $104.7 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 September 30, 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 and nine month periods ended September 30, 2009 and 2008:

		Three Months Ended September 30,				
(In thousands)		**2009**			2008	
Accumulated Other Comprehensive Income / (Loss) Beginning of Period			**$ 158,273**			$ (182,602)
Net Income		**$ 38,897**			$ 66,990	
Other Comprehensive Income / (Loss), net of taxes:						
Reclassification Adjustment for Settled Contracts, net of taxes of $40,185 and $(3,758), respectively		**(67,843)**			6,300	
Changes in Fair Value of Hedge Positions, net of taxes of $(837) and $(171,149), respectively		**1,415**			291,061	
Defined Benefit Pension and Postretirement Plans:						
Amortization of Net Obligation at Transition, net of taxes of $(59) and $(58), respectively	**$ 99**			$ 100		
Amortization of Prior Service Cost, net of taxes of $(66) and $(93), respectively	**113**			158		
Amortization of Net Loss, net of taxes of $(358) and $(152), respectively	**605**	**817**		254	512	
Foreign Currency Translation Adjustment, net of taxes of $43 and $1,864, respectively		**(73)**			(3,189)	
Total Other Comprehensive Income / (Loss)		**(65,684)**	**(65,684)**		294,684	294,684
Comprehensive Income / (Loss)		**$ (26,787)**			$ 361,674	
Accumulated Other Comprehensive Income End of Period			**$ 92,589**			$ 112,082

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(In thousands)		Nine Months Ended September 30, 2009			2008	
Accumulated Other Comprehensive Income / (Loss) Beginning of Period			**$ 186,426**			$ (894)
Net Income		**$ 111,979**			$ 167,590	
Other Comprehensive Income / (Loss), net of taxes:						
Reclassification Adjustment for Settled Contracts,net of taxes of $113,598 and $(13,541), respectively		**(190,452)**			22,957	
Changes in Fair Value of Hedge Positions, net of taxes of $(52,441) and $(55,122), respectively		**87,204**			93,513	
Defined Benefit Pension and Postretirement Plans:						
Amortization of Net Obligation at Transition, net of taxes of $(177) and $(175), respectively	**$ 297**			$ 299		
Amortization of Prior Service Cost, net of taxes of $(200) and $(279), respectively	**338**			473		
Amortization of Net Loss, net of taxes of $(1,075) and $(452), respectively	**1,815**	**2,450**		766	1,538	
Foreign Currency Translation Adjustment, net of taxes of $(4,124) and $3,033, respectively		**6,961**			(5,032)	
Total Other Comprehensive Income / (Loss)		**(93,837)**	**(93,837)**		112,976	112,976
Comprehensive Income		**$ 18,142**			$ 280,566	
Accumulated Other Comprehensive Income End of Period			**$ 92,589**			$ 112,082

Changes in the components of Accumulated Other Comprehensive Income, net of taxes, for the nine months ended September 30, 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 $61,157	(103,248)			(103,248)
Net change in defined benefit pension and postretirement plans, net of taxes of $(1,452)		2,450		2,450
Change in foreign currency translation adjustment, net of taxes of $(4,124)			6,961	6,961
Balance at September 30, 2009	**$ 119,820**	**$ (27,158)**	**$ (73)**	**$ 92,589**

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9. PENSION AND OTHER POSTRETIREMENT BENEFITS

The components of net periodic benefit costs for the three and nine months ended September 30, 2009 and 2008 were as follows:

(In thousands)	Three Months Ended September 30, 2009	Three Months Ended September 30, 2008	Nine Months Ended September 30, 2009	Nine Months Ended September 30, 2008
Qualified and Non-Qualified Pension Plans				
Current Period Service Cost	**$ 861**	$ 828	**$ 2,583**	$ 2,485
Interest Cost	**928**	818	**2,784**	2,454
Expected Return on Plan Assets	**(671)**	(884)	**(2,013)**	(2,651)
Amortization of Prior Service Cost	**13**	13	**39**	38
Amortization of Net Loss	**794**	294	**2,382**	881
Net Periodic Pension Cost	**$ 1,925**	$ 1,069	**$ 5,775**	$ 3,207
Postretirement Benefits Other than Pension Plans				
Current Period Service Cost	**$ 320**	$ 271	**$ 960**	$ 812
Interest Cost	**398**	345	**1,195**	1,035
Amortization of Prior Service Cost	**167**	238	**500**	714
Amortization of Net Loss	**169**	112	**507**	336
Amortization of Net Obligation at Transition	**158**	158	**474**	474
Total Postretirement Benefit Cost	**$ 1,212**	$ 1,124	**$ 3,636**	$ 3,371

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. In May 2009, the Company made a contribution of $10 million to its qualified pension plan.

10. STOCK-BASED COMPENSATION

Compensation expense charged against income for stock-based awards (including the supplemental employee incentive plans) during the nine months ended September 30, 2009 and 2008 was $16.6 million and $29.6 million, respectively, and is included in General and Administrative Expense in the Condensed Consolidated Statement of Operations.

During the third quarter of 2009, the Company realized a $13.1 million tax benefit related primarily to the federal tax deduction in excess of book compensation cost for employee stock-based compensation for 2008 and, to a lesser extent, book compensation cost exceeding federal tax deduction for 2009 and state tax deductions for 2007. For regular federal income tax purposes, the Company was in a net operating loss position in 2008. In accordance with ASC 718, the Company is able to recognize this tax benefit only to the extent it reduces the Company s income taxes payable. As the Company carried back net operating losses concurrent with its 2008 tax return filing, the income tax benefit related to stock-based compensation was recorded in 2009. 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. For further information regarding Stock-Based Compensation or the Company s Incentive Plans, please refer to Note 10 of the Notes to the Consolidated Financial Statements in the Form 10-K.

Restricted Stock Awards

During the first nine months of 2009, the Compensation Committee granted 140,060 restricted stock awards with a weighted-average grant date per share value of $34.74. The fair value of restricted stock grants is based on the average of the high and low stock price on the grant date. During the first nine months of 2009, 39,240 restricted stock awards vested with a weighted-average grant date per share value of $27.29.

Compensation expense recorded for all unvested restricted stock awards for the nine months ended September 30, 2009 and 2008 was $0.7 million and $1.2 million, respectively. Compensation expense recorded for all unvested restricted stock awards for the third quarter of 2009 and 2008 was $0.3 million and $0.2 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 nine months ended September 30, 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 nine months of both 2009 and 2008 was $0.8 million. There was no expense recorded in the third quarter of either 2009 or 2008.

Stock Appreciation Rights

During the first nine months 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:

	Nine Months Ended September 30, 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 nine months of both 2009 and 2008 for SARs was $1.5 million. Included in these amounts were $0.7 million and $0.5 million in the first nine months of 2009 and 2008, respectively, related to the immediate expensing of shares granted in 2009 and 2008 to retirement-eligible employees. Compensation expense in the third quarter of 2009 and 2008 was $0.2 million and $0.3 million, respectively.

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 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 September 30, 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 September 30, 2009, it is considered probable that this performance metric will be met for 2009.

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 ASC 718 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 50% 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 September 30, 2009 closing price of the Company s stock ($35.75). 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 September 30, 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.

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	September 30, 2009
Risk Free Rate of Return	**0.1% - 1.1%**
Stock Price Volatility	**42.4% - 81.9%**
Expected Dividend	**0.3%**

The Monte Carlo value per share for the liability component for all outstanding market condition performance share awards ranged from $8.02 to $12.06 at September 30, 2009. The long-term liability for market condition performance share awards, included in Other Liabilities in the Condensed Consolidated Balance Sheet, at September 30, 2009 and December 31, 2008 was $1.2 million and $0.3 million, respectively. The short-term liability, included in Accrued Liabilities in the Condensed Consolidated Balance Sheet, at September 30, 2009 and December 31, 2008, for market condition performance share awards was $0.7 million and $2.5 million, respectively.

During the first nine months of 2009, 332,642 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. During the first quarter of 2009, 60,740 shares vested (valued at $2.5 million) which represents 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. During the second quarter of 2009, 10,302 performance shares vested as a result of early vesting schedules for certain employees. Additionally, 63,960 performance shares were forfeited during the first nine months of 2009.

As of September 30, 2009, 250,800 shares of the Company s common stock representing vested performance share awards were deferred into the Rabbi Trust Deferred Compensation Plan. During the third quarter of 2009, 5,600 shares were sold out of the plan. For the first nine months of 2009, an increase to the rabbi trust deferred compensation liability of $2.3 million was recognized, primarily representing the increase in the closing price of all shares from December 31, 2008 to September 30, 2009. This increase 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 nine months ended September 30, 2009 and 2008 was $13.5 million and $10.3 million, respectively. Total compensation cost recognized for both the equity and liability components of all performance share awards as well as expense related to the shares deferred into the rabbi trust during the third quarter of 2009 and 2008 was a charge of $4.7 million and a credit of $10.2 million, respectively.

11. INCREASE IN AUTHORIZED SHARES

In April 2009, the stockholders of the Company approved an increase in the authorized number of shares of common stock from 120 million to 240 million shares. The Company also decreased the number of shares of Series A Junior Participating Preferred Stock reserved for issuance from 1,200,000 to 800,000. The shares of Series A Junior Participating Preferred Stock are issuable pursuant to the Company s Preferred Stock Purchase Rights Plan.

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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 September 30, 2009, and the related condensed consolidated statements of operations for the three-month and nine-month periods ended September 30, 2009 and 2008 and the condensed consolidated statement of cash flows for the nine-month periods ended September 30, 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

October 29, 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 and nine month periods ended September 30, 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).

Certain prior year amounts have been reclassified to reflect changes in presenting the geographic areas for which we conduct our operations. These areas consist of the North (comprised of the East and Rocky Mountain areas), South (comprised of the Gulf Coast and Anadarko areas) and Canada. In previous periods, we presented the geographic areas as East, Gulf Coast, West and Canada.

Overview

On an equivalent basis, our production level for the nine months ended September 30, 2009 increased by 10% compared to the nine months ended September 30, 2008. For the nine months ended September 30, 2009, we produced 76.7 Bcfe compared to production of 69.6 Bcfe for the nine months ended September 30, 2008. Natural gas production was 73.0 Bcf and oil production was 607 Mbbls for the first nine months of 2009. Natural gas production increased by 10% when compared to the first nine months of 2008, which had production of 66.1 Bcf. This increase was primarily a result of increased production in the North region associated with the increased drilling program in Susquehanna County, Pennsylvania as well as increased natural gas production in the South region associated with the properties we acquired in east Texas in August 2008 and drilling in the County Line field. Partially offsetting these production gains were decreases in production in Canada due to the sale of our Canadian properties in April 2009, as well as reduced drilling activity in Canada, Oklahoma and Wyoming. Oil production increased by five percent, from 580 Mbbls in the first nine months of 2008 to 607 Mbbls produced in the first nine months of 2009. This was primarily the result of increased production in the South region associated with the properties we acquired in east Texas in August 2008, partially offset by a decrease in production in Canada due to the sale of our Canadian properties in April 2009.

Our average realized natural gas price for the first nine months of 2009 was $7.39 per Mcf, 14% lower than the $8.64 per Mcf price realized in the first nine months of 2008. Our average realized crude oil price for the first nine months of 2009 was $82.48 per Bbl, 13% lower than the $94.93 per Bbl price realized in the first nine months 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.

Operating revenues for the nine months ended September 30, 2009 decreased by $67.5 million, or nine percent, from the nine months ended September 30, 2008 as the lower commodity prices noted above more than offset the higher equivalent production. Natural gas production revenues decreased by $31.0 million, or five percent, for the nine months ended September 30, 2009 as compared to the nine months ended September 30, 2008 due to the decrease in realized natural gas prices, partially offset by the increase in natural gas production. Crude oil and condensate revenues decreased by $5.1 million, or nine percent, for the first nine months of 2009 as compared to the first nine months of 2008, due to a decrease in realized crude oil prices, partially offset by the increase in crude oil production. Brokered natural gas revenues decreased by $32.5 million, or 38%, due to a decrease in sales price, partially offset by an increase in brokered volumes.

In addition to production volumes and commodity prices, finding and developing sufficient amounts of crude oil and natural gas reserves at economical costs are critical to our long-term success. For 2009, we expect to spend approximately $580 million in capital and exploration expenditures, increased from $500 million disclosed at June 30, 2009, due primarily to our lease acquisition efforts in the highly competitive Marcellus shale basin. 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 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. For the nine months ended September 30, 2009, approximately $367.1 million has been invested in our exploration and development efforts.

During the first nine months of 2009, we drilled 119 gross wells (107 development, six exploratory and six extension wells) with a success rate of 98% compared to 333 gross wells (318 development, 12 exploratory and three extension wells) with a success rate of 99% for the comparable period of the prior year. For the full year of 2009, we plan to drill approximately 153 gross wells.

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 maintain spending discipline and manage our balance sheet in an effort to ensure sufficient liquidity, including cash resources and available credit. We believe these strategies are appropriate for our portfolio of projects and the current industry environment and will continue to add shareholder value over the long-term.

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

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

Financial Condition

Capital Resources and Liquidity

Our primary sources of cash for the nine months ended September 30, 2009 were funds generated from the sale of natural gas and crude oil production and, to a lesser extent, the sales of properties during the period, as disclosed in Note 2 of the Notes to the Condensed Consolidated Financial Statements. These cash flows were primarily used to fund our development and exploratory expenditures, in addition to payments for debt service, debt issuance costs, contributions to our pension plan and 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 credit availability and liquidity to meet our working capital requirements.

	Nine Months Ended September 30,	
(In thousands)	**2009**	**2008**
Cash Flows Provided by Operating Activities	**$ 417,130**	$ 424,728
Cash Flows Used in Investing Activities	**(345,997)**	(1,181,953)
Cash Flows (Used in) / Provided by Financing Activities	**(63,564)**	786,101
Net Increase in Cash and Cash Equivalents	**$ 7,569**	$ 28,876

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***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 nine months of 2009 decreased by $7.6 million over the first nine months of 2008. This decrease was mainly due to an increase in working capital changes as a result of lower trade accounts receivable balances due to lower commodity prices and lower accounts payable due to lower capital expenditures and lower commodity prices. Average realized natural gas prices decreased by 14% for the first nine months of 2009 compared to the first nine months of 2008 and average realized crude oil prices decreased by 13% compared to the same period. Equivalent production volumes increased by 10% for the nine months ended September 30, 2009 compared to the nine months ended September 30, 2008 as a result of higher natural gas and crude oil 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.

For 2009, we have natural gas price swaps covering 16.1 Bcf of our 2009 gas production at an average price of $12.18 per Mcf and natural gas price collars covering 47.3 Bcf of our 2009 gas production, with a weighted-average floor of $9.40 per Mcf and a weighted-average ceiling of $12.39 per Mcf. As of September 30, 2009, we have natural gas price swaps covering 19.3 Bcf of our 2010 gas production at an average price of $11.43 per Mcf, and no natural gas price collars. Accordingly, based on our current hedge position, we will be more subject to the effects of natural gas price volatility in 2010 than in 2009. In addition, given the current market for derivatives, if we were to hedge all our 2010 production, we would expect our realized prices to be lower than our 2009 realized prices.

***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 decreased by $836.0 million from the first nine months of 2008 compared to the first nine months of 2009. The decrease was due to a decrease of $769.5 million in acquisitions and capital expenditures and an increase of $79.0 million of proceeds from the sale of assets, partially offset by an increase of $12.5 million in exploration expenditures. In August 2008, we completed the acquisition of producing properties, leasehold acreage and a natural gas gathering infrastructure in east Texas for total net cash consideration of approximately $604.0 million.

***Financing Activities*.** Cash flows provided by financing activities decreased by $849.7 million from the first nine months of 2008 to the first nine months of 2009. This was primarily due to a decrease in borrowings from debt of $645 million, partially offset by a decrease in repayments of debt of $118 million, and a decrease in net proceeds from the sale of common stock of $316.1 million primarily due to our June 2008 issuance of 5,002,500 shares of common stock in a public offering for net proceeds of $313.5 million. Common stock proceeds and debt borrowings in 2008 were largely used to finance the acquisition of East Texas properties and undeveloped acreage. Cash paid for capitalized debt issuance costs and dividends increased by a total of $8.6 million, partially offset by an increase of $2.1 million in the tax benefit associated with stock-based compensation.

At September 30, 2009, we had $128 million of borrowings outstanding under our unsecured credit facility at a weighted-average interest rate of 3.7%. In April 2009, we entered into a new revolving credit facility and terminated our prior credit facility (see Note 4 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 and the outstanding principal balance of our senior notes. We strive to manage our debt at a level below the available credit line in order to maintain excess borrowing capacity. Our revolving credit facility includes a covenant limiting our total debt. Management believes that, with internally generated cash, existing cash and availability under our revolving credit facility, we have the capacity to finance our spending plans and maintain our strong financial position. At the same time, we will closely monitor the capital markets.

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Capitalization

Information about our capitalization is as follows:

(Dollars in millions)	September 30, 2009	December 31, 2008
Debt[1]	**$ 810.0**	$ 867.0
Stockholders Equity	**1,823.8**	1,790.6
Total Capitalization	**$ 2,633.8**	$ 2,657.6
Debt to Capitalization	**31%**	33%
Cash and Cash Equivalents	**$ 35.7**	$ 28.1

(1) Includes $20 million and $35.9 million of current portion of long-term debt at September 30, 2009 and December 31, 2008, respectively. Includes $128 million and $185 million of borrowings outstanding under our revolving credit facility at September 30, 2009 and December 31, 2008, respectively.

During the nine months ended September 30, 2009, we paid dividends of $9.3 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.

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 nine months ended September 30, 2009 and 2008:

(In millions)	Nine Months Ended September 30, 2009	2008
Capital Expenditures		
Drilling and Facilities[1]	**$ 294.7**	$ 415.5
Leasehold Acquisitions	**20.8**	106.0
Acquisitions	**0.4**	624.4
Pipeline and Gathering	**15.3**	25.4
Other	**4.6**	7.5
	335.8	1,178.8
Exploration Expense	**31.3**	18.8
Total	**$ 367.1**	$ 1,197.6

(1) Includes Canadian currency translation effects of $4.6 million and $(9.2) million in 2009 and 2008, respectively.

For the full year of 2009, we plan to drill approximately 153 gross (127.3 net) wells. This 2009 drilling program includes approximately $580 million in total capital and exploration expenditures. See the Overview discussion for additional information regarding the current year drilling program. We will continue to assess the natural gas and crude oil price environment and our liquidity position and may increase or decrease the capital and exploration expenditures accordingly.

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Contractual Obligations

At September 30, 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 July 2009, the Financial Accounting Standards Board (FASB) issued Accounting Standards Codification (ASC) 105, Generally Accepted Accounting Principles, establishing the accounting standards codification and the hierarchy of generally accepted accounting principles (GAAP) as the sole source of authoritative non-governmental U.S. GAAP. The Codification was not intended to change U.S. GAAP; however, references to various accounting pronouncements and literature will now differ from what was previously being used in practice. Authoritative literature is now referenced by topic rather than by type of standard. As of July 1, 2009, the FASB no longer issues Statements, Interpretations, Staff Positions or EITF Abstracts. The FASB now communicates new accounting standards by issuing an Accounting Standards Update (ASU). All guidance in the Codification has an equal level of authority. ASC 105 is effective for financial statements that cover interim and annual periods ending after September 15, 2009, and supersedes all accounting standards in U.S. GAAP, aside from those issued by the SEC. There was no impact on our financial position, results of operations or cash flows as a result of the Codification.

In February 2008, the FASB issued an amendment to ASC 820, Fair Value Measurements and Disclosures, 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 ASC 820. Effective January 1, 2009, we applied these amendments of ASC 820 discussed above and there was no material impact on our financial statements. For further information, please refer to Note 7 of the Notes to the Condensed Consolidated Financial Statements.

Effective January 1, 2009, we adopted amendments that the FASB made to ASC 260, Earnings Per Share, regarding determining whether instruments granted in share-based payment transactions are participating securities. The adoption of these amendments 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 amended the disclosure requirements prescribed in ASC 815, Derivatives and Hedging. We adopted these amendments 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.

In April 2009, the FASB amended guidance in ASC 820 regarding determining fair value when the volume and level of activity for an asset or liability has significantly decreased and identifying transactions that are not orderly. 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 ASC 820 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. These amendments became effective for interim and annual reporting periods ending after June 15, 2009 and did not have a material impact on our financial position, results of operations or cash flows.

In April 2009, the FASB amended ASC 825, 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. These amendments became effective for interim reporting periods ending after June 15, 2009, and we have provided interim disclosures regarding the fair value of debt instruments in Note 4 of the Notes to the Condensed Consolidated Financial Statements. Comparative disclosures are only required for periods ending after the initial adoption. There was no material impact on our financial position, results of operations or cash flows as a result of the adoption.

In April 2009, the FASB amended the other-than-temporary impairment guidance for debt securities in ASC 320, Investments-Debt and Equity 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. There were no amendments made to the recognition and measurement guidance for equity securities, but a new method of recognizing and reporting for debt securities was established. Disclosure requirements for impaired debt and equity securities have been expanded significantly and are now required quarterly, as well as annually. These amendments became effective for interim and annual reporting periods ending after June 15, 2009 and did not have a material impact on our financial position, results of operations or cash flows. Comparative disclosures are only required for periods ending after the initial adoption.

In June 2009, the FASB amended ASC 855, Subsequent Events, to require entities to disclose the date through which they have evaluated subsequent events and whether the date corresponds with the release of their financial statements. In addition, a new concept of financial statements being available to be issued was introduced. These amendments became effective for interim and annual periods ending after June 15, 2009 and did not have any impact on our financial position, results of operations or cash flows.

In August 2009, the FASB issued Accounting Standards Update (ASU) No. 2009-05, Fair Value Measurement and Disclosures: Measuring Liabilities at Fair Value, which provides clarification on measuring liabilities at fair value when a quoted price in an active market is not available. ASU No. 2009-05 specifies that in cases where a quoted price in an active market is not available, a valuation technique should be applied that uses either the quote of the liability when traded as an asset, the quoted prices for similar liabilities or similar liabilities when traded as assets, or another valuation technique consistent with existing fair value measurement guidance. Valuation methods discussed include using an income approach, such as a present value technique, or a market approach based on the amount at the measurement date that the reporting entity would pay to transfer the identical liability or would receive to enter into the identical liability. Entities are not required to include a separate input or adjustment to other inputs relating to the existence of a restriction that prevents the transfer of the liability. ASU No. 2009-05 is codified in ASC 820-10 and is effective for the first reporting period (including interim periods) beginning after issuance. There was no impact on our financial position, results of operations or cash flows as a result of the adoption of ASU No. 2009-05.

Recently Issued Accounting Pronouncements

In June 2009, the FASB issued Statement of Financial Accounting Standards (SFAS) No. 166, Accounting for Transfers of Financial Assets. SFAS No. 166 has not yet been codified, but revises ASC 860, Transfers and Servicing, and will require entities to provide more information about sales of securitized financial assets and similar transactions, particularly if the seller retains some risk to the assets. SFAS No. 166 will be effective at the beginning of the first fiscal year beginning after November 15, 2009. As we do not anticipate having any of these types of transactions in the near future, SFAS No. 166 is not expected to have any 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

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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.

In December 2008, the FASB issued an amendment to ASC 715-20, Compensation Retirement Benefits Defined Benefit Plans General, which requires enhanced disclosures regarding company benefit plans. Disclosure regarding plan assets should include discussion about how investment allocation decisions are made, the major categories of plan assets, the inputs and valuation techniques used to measure plan assets and significant concentrations of risk within plan assets. These amendments to ASC 715-20 are effective for fiscal years ending after December 15, 2009, and earlier application is permitted. Prior year periods presented for comparative purposes are not required to comply. We do not believe that these amendments to ASC 715-20 will have a material impact on our financial position, results of operations or cash flows.

Results of Operations

Third Quarters of 2009 and 2008 Compared

We reported net income in the third quarter of 2009 of $38.9 million, or $0.38 per share. For the third quarter of 2008, we reported net income of $67.0 million, or $0.65 per share. Net income decreased in the third quarter of 2009 by $28.1 million, primarily due to a decrease in operating revenues, partially offset by a decrease in income tax expense. Operating revenues decreased by $37.8 million, largely due to decreases in natural gas production revenues and brokered natural gas revenues and, to a lesser extent, crude oil and condensate revenues. Operating expenses increased by $2.8 million between periods due primarily to increases in general and administrative expenses, exploration expense and depreciation, depletion and amortization, partially offset by decreased brokered natural gas costs and taxes other than income. In addition, net income was impacted in the third quarter of 2009 by a decrease in income tax expense. Income tax expense was lower in the third quarter of 2009 as a result of a decrease in operating income, as discussed above, in addition to a decrease 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 $7.40 per Mcf for the three months ended September 30, 2009 compared to $8.66 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 $4.25 per Mcf in 2009 and decreased the price by $0.30 per Mcf in 2008. The following table excludes the unrealized loss from the change in fair value of our basis swaps of $1.2 million for the quarter ended September 30, 2009 and the unrealized gain from the change in derivative fair value of $1.3 million for the quarter ended September 30, 2008, which have been included within Natural Gas Production Revenues in the Condensed Consolidated Statement of Operations.

	Three Months Ended September 30,		Variance	
	2009	**2008**	**Amount**	**Percent**
Natural Gas Production *(Mmcf)*				
North	**12,208**	9,792	2,416	25%
South	**11,986**	12,404	(418)	(3%)
Canada		780	(780)	(100%)
Total Company	**24,194**	22,976	1,218	5%
Natural Gas Production Sales Price *($/Mcf)*				
North	**$ 6.28**	$ 7.89	$ (1.61)	(20%)
South	**$ 8.53**	$ 9.34	$ (0.81)	(9%)
Canada	**$**	$ 7.60	$ (7.60)	(100%)
Total Company	**$ 7.40**	$ 8.66	$ (1.26)	(15%)
Natural Gas Production Revenue *(In thousands)*				
North	**$ 76,632**	$ 77,295	$ (663)	(1%)
South	**102,259**	115,796	(13,537)	(12%)
Canada	**149**	5,928	(5,779)	(97%)
Total Company	**$ 179,040**	$ 199,019	$ (19,979)	(10%)
Price Variance Impact on Natural Gas Production Revenue *(In thousands)*				
North	**$ (19,735)**			
South	**(9,632)**			
Canada				
Total Company	**$ (29,367)**			
Volume Variance Impact on Natural Gas Production Revenue *(In thousands)*				
North	**$ 19,072**			
South	**(3,905)**			
Canada	**(5,779)**			
Total Company	**$ 9,388**			

The decrease in Natural Gas Production Revenue of $20.0 million, excluding the impact of the unrealized losses discussed above, is due to primarily to the decrease in realized natural gas prices in all regions. In addition, natural gas production declined in the South due to lower capital expenditures and natural decline and in Canada due to the sale of our Canadian properties in April 2009. Partially offsetting these decreases was an increase in natural gas production in the North region associated with the initiation of production in Susquehanna County, Pennsylvania in the third quarter of 2008 and with increased drilling in the Marcellus Shale prospect.

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Brokered Natural Gas Revenue and Cost

	Three Months Ended September 30, 2009	2008	Variance Amount	Percent
Sales Price *($/Mcf)*	**$ 4.04**	$ 11.77	$ (7.73)	(66%)
Volume Brokered *(Mmcf)*	**x 2,238**	x 2,027	211	10%
Brokered Natural Gas Revenues *(In thousands)*	**$ 9,032**	$ 23,855		
Purchase Price *($/Mcf)*	**$ 3.48**	$ 10.31	$ (6.83)	(66%)
Volume Brokered *(Mmcf)*	**x 2,238**	x 2,027	211	10%
Brokered Natural Gas Cost *(In thousands)*	**$ 7,786**	$ 20,891		
Brokered Natural Gas Margin *(In thousands)*	**$ 1,246**	$ 2,964	$ (1,718)	(58%)

(In thousands)	
Sales Price Variance Impact on Revenue	**$ (17,306)**
Volume Variance Impact on Revenue	**2,483**
	$ (14,823)

(In thousands)	
Purchase Price Variance Impact on Purchases	**$ 15,280**
Volume Variance Impact on Purchases	**(2,175)**
	$ 13,105

The decreased brokered natural gas margin of $1.7 million is a result of a decrease in sales price that outpaced the decrease in purchase price, partially offset by an increase in volumes brokered.

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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 $87.49 per Bbl for the third quarter of 2009 compared to $99.34 per Bbl for the third quarter of 2008. These prices include the realized impact of derivative instrument settlements, which increased the price by $23.40 in 2009 and decreased the price by $15.39 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 September 30, 2009 and 2008.

	Three Months Ended September 30,		Variance	
	2009	**2008**	**Amount**	**Percent**
Crude Oil Production *(Mbbl)*				
North	**30**	31	(1)	(3%)
South	**194**	164	30	18%
Canada		6	(6)	(100%)
Total Company	**224**	201	23	11%
Crude Oil Sales Price *($/Bbl)*				
North	**$ 58.49**	$ 109.50	$ (51.01)	(47%)
South	**$ 92.12**	$ 97.37	$ (5.25)	(5%)
Canada	**$**	$ 100.46	$ (100.46)	(100%)
Total Company	**$ 87.49**	$ 99.34	$ (11.85)	(12%)
Crude Oil Revenue *(In thousands)*				
North	**$ 1,728**	$ 3,405	$ (1,677)	(49%)
South	**17,846**	15,947	1,899	12%
Canada		650	(650)	(100%)
Total Company	**$ 19,574**	$ 20,002	$ (428)	(2%)
Price Variance Impact on Crude Oil Revenue *(In thousands)*				
North	**$ (1,617)**			
South	**(1,015)**			
Canada				
Total Company	**$ (2,632)**			
Volume Variance Impact on Crude Oil Revenue *(In thousands)*				
North	**$ (60)**			
South	**2,914**			
Canada	**(650)**			
Total Company	**$ 2,204**			

The decrease in realized crude oil prices in all regions, partially offset by an increase in crude oil production (due to an increase in South production), resulted in a net revenue decrease of $0.4 million.

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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 September 30,			
	2009		2008	
(In thousands)	Realized	Unrealized	Realized	Unrealized
Operating Revenues Increase / (Decrease) to Revenue				
Cash Flow Hedges				
Natural Gas Production	**$ 102,787**	**$**	$ (6,964)	$ 1,260
Crude Oil	**5,241**		(3,093)	
Total Cash Flow Hedges	**$ 108,028**	**$**	$ (10,057)	$ 1,260
Other Derivative Financial Instruments				
Natural Gas Basis Swaps		**(1,233)**		
Total Other Derivative Financial Instruments		**(1,233)**		
Total Cash Flow Hedges and Other Derivative Financial Instruments	**$ 108,028**	**$ (1,233)**	$ (10,057)	$ 1,260

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 Bank of Montreal, BNP Paribas, Goldman Sachs, JPMorgan Chase and Morgan Stanley.

Operating Expenses

Total costs and expenses from operations increased by $2.8 million in the third quarter of 2009 compared to the same period of 2008. The primary reasons for this fluctuation are as follows:

General and Administrative expenses increased by $15.1 million from the third quarter of 2008 compared to the third quarter of 2009. This is primarily due to an increase in stock-based compensation expense from a credit of $9.6 million in the third quarter of 2008 to an expense of $5.3 million in the third quarter of 2009. We recorded credits in the third quarter of 2008 related to a reduction in the liability associated with the value of performance shares in our rabbi trust due to a decline in our stock price, as well as a reduction in our performance share liability related to the expected payout of future performance share awards in which we are ranked against our peers.

Brokered Natural Gas Cost decreased by $13.1 million from the third quarter of 2008 compared to the third quarter of 2009. See the preceding table titled Brokered Natural Gas Revenue and Cost for further analysis.

Taxes Other Than Income decreased by $9.9 million in the third quarter of 2009 compared with the third quarter of 2008 due primarily to lower production taxes as a result of lower average natural gas and crude oil prices.

Exploration expense increased by $8.0 million from the third quarter of 2008 compared to the third quarter of 2009 primarily due to higher charges for idle contract rigs and higher dry hole and geological and geophysical costs.

Depreciation, Depletion and Amortization increased by $6.0 million from the third quarter of 2008 compared to the third 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.

Interest Expense, Net

Interest expense, net increased by $4.4 million in the third quarter of 2009 compared to the third quarter of 2008 primarily due to increased interest expense related to the $492 million principal amount of debt we issued in our July and December 2008 private placements. Weighted-average borrowings under our credit facility based on daily balances were approximately $145 million during the third quarter of 2009 compared to approximately $117 million during the third quarter of 2008. The weighted-average effective interest rate on the credit facility decreased to approximately 3.6% during the third quarter of 2009 compared to approximately 4.4% during the third quarter of 2008.

Income Tax Expense

Income tax expense decreased by $16.3 million due to a decrease in our pre-tax income. The effective tax rates for the third quarter of 2009 and 2008 were 35.0% and 35.7%, respectively.

Nine Months of 2009 and 2008 Compared

We reported net income in the first nine months of 2009 of $112.0 million, or $1.08 per share. For the first nine months of 2008, we reported net income of $167.6 million, or $1.68 per share. Net income decreased in the first nine months of 2009 by $55.6 million, primarily due to a decrease in operating revenues and an increase in interest expense, partially offset by decreased operating and income tax expenses. Operating revenues decreased by $67.5 million largely due to decreases in brokered natural gas and natural gas production revenues as well as crude oil and condensate revenues. Operating expenses decreased by $5.2 million between periods due primarily to decreases in brokered natural gas costs, taxes other than income and general and administrative expenses, partially offset by increased depreciation, depletion and amortization, exploration expense, direct operations and impairment of unproved properties. In addition, net income was impacted in the first nine months of 2009 by higher interest expense, decreased income tax expense and, to a lesser extent, loss on sale of assets. Income tax expense was lower in the first nine months of 2009 as a result of a decrease in operating income, as discussed above, and a slight decrease 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 $7.39 per Mcf for the nine months ended September 30, 2009 compared to $8.64 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 $3.91 per Mcf in 2009 and decreased the price by $0.42 per Mcf in 2008. The following table excludes the unrealized loss from the change in fair value of our basis swaps of $0.4 million for the nine months ended September 30, 2009 and the unrealized loss from the change in derivative fair value of $1.6 million for the nine months ended September 30, 2008, which have been included within Natural Gas Production Revenues in the Condensed Consolidated Statement of Operations.

	Nine Months Ended September 30, 2009	Nine Months Ended September 30, 2008	Variance Amount	Variance Percent
Natural Gas Production *(Mmcf)*				
North	**34,785**	29,350	5,435	19%
South	**37,236**	33,378	3,858	12%
Canada	**958**	3,369	(2,411)	(72%)
Total Company	**72,979**	66,097	6,882	10%
Natural Gas Production Sales Price *($/Mcf)*				
North	**$ 6.56**	$ 8.14	$ (1.58)	(19%)
South	**$ 8.25**	$ 9.17	$ (0.92)	(10%)
Canada	**$ 3.56**	$ 7.84	$ (4.28)	(55%)
Total Company	**$ 7.39**	$ 8.64	$ (1.25)	(14%)
Natural Gas Production Revenue *(In thousands)*				
North	**$ 228,290**	$ 238,818	$ (10,528)	(4%)
South	**307,263**	305,947	1,316	0%
Canada	**3,407**	26,411	(23,004)	(87%)
Total Company	**$ 538,960**	$ 571,176	$ (32,216)	(6%)
Price Variance Impact on Natural Gas Production Revenue *(In thousands)*				
North	**$ (54,752)**			
South	**(34,045)**			
Canada	**(4,099)**			
Total Company	**$ (92,896)**			
Volume Variance Impact on Natural Gas Production Revenue *(In thousands)*				
North	**$ 44,224**			
South	**35,361**			
Canada	**(18,905)**			
Total Company	**$ 60,680**			

The decrease in Natural Gas Production Revenue of $32.2 million, excluding the impact of the unrealized gains and losses discussed above, is due to a decrease in realized natural gas prices in all regions, partially offset by an increase in natural gas production. This increase in natural gas production was primarily a result of increased production in the North region associated with the initiation of production in Susquehanna County, Pennsylvania in the third quarter of 2008 and increased drilling in the Marcellus Shale prospect as well as increased natural gas production in the South region associated with the properties we acquired in east Texas in August 2008 and drilling in the County Line field. Partially offsetting these production gains were decreases in production in Canada due to the sale of our Canadian properties in April 2009.

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Brokered Natural Gas Revenue and Cost

	Nine Months Ended September 30, 2009	2008	Variance Amount	Percent
Sales Price *($/Mcf)*	**$ 6.49**	$ 10.81	$ (4.32)	(40%)
Volume Brokered *(Mmcf)*	**x 8,337**	x 8,017	320	4%
Brokered Natural Gas Revenues *(In thousands)*	**$ 54,117**	$ 86,663		
Purchase Price *($/Mcf)*	**$ 5.78**	$ 9.40	$ (3.62)	(39%)
Volume Brokered *(Mmcf)*	**x 8,337**	x 8,017	320	4%
Brokered Natural Gas Cost *(In thousands)*	**$ 48,219**	$ 75,321		
Brokered Natural Gas Margin *(In thousands)*	**$ 5,898**	$ 11,342	$ (5,444)	(48%)

(In thousands)	
Sales Price Variance Impact on Revenue	**$ (36,005)**
Volume Variance Impact on Revenue	**3,459**
	$ (32,546)

(In thousands)	
Purchase Price Variance Impact on Purchases	**$ 30,110**
Volume Variance Impact on Purchases	**(3,008)**
	$ 27,102

The decreased brokered natural gas margin of $5.4 million is a result of a decrease in sales price that outpaced the decrease in purchase price, partially offset by an increase in volumes brokered.

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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 $82.48 per Bbl for the first nine months of 2009 compared to $94.93 per Bbl for the first nine months of 2008. These prices include the realized impact of derivative instrument settlements, which increased the price by $30.64 in 2009 and decreased the price by $15.05 per Bbl in 2008. There was no revenue impact from the unrealized change in crude oil and condensate derivative fair value for the nine months ended September 30, 2009 and 2008.

	Nine Months Ended September 30,		Variance	
	2009	**2008**	**Amount**	**Percent**
Crude Oil Production *(Mbbl)*				
North	**85**	84	1	1%
South	**515**	479	36	8%
Canada	**7**	17	(10)	(59%)
Total Company	**607**	580	27	5%
Crude Oil Sales Price *($/Bbl)*				
North	**$ 48.22**	$ 107.21	$ (58.99)	(55%)
South	**$ 88.75**	$ 92.89	$ (4.14)	(4%)
Canada	**$ 33.97**	$ 92.03	$ (58.06)	(63%)
Total Company	**$ 82.48**	$ 94.93	$ (12.45)	(13%)
Crude Oil Revenue *(In thousands)*				
North	**$ 4,092**	$ 8,985	$ (4,893)	(54%)
South	**45,708**	44,455	1,253	3%
Canada	**226**	1,649	(1,423)	(86%)
Total Company	**$ 50,026**	$ 55,089	$ (5,063)	(9%)
Price Variance Impact on Crude Oil Revenue *(In thousands)*				
North	**$ (5,005)**			
South	**(2,128)**			
Canada	**(387)**			
Total Company	**$ (7,520)**			
Volume Variance Impact on Crude Oil Revenue *(In thousands)*				
North	**$ 112**			
South	**3,381**			
Canada	**(1,036)**			
Total Company	**$ 2,457**			

The decrease in realized crude oil prices in all regions, partially offset by an increase in crude oil production, resulted in a net revenue decrease of $5.1 million. The increase in crude oil production was primarily the result of increased production in the South region associated with the properties we acquired in east Texas in August 2008, partially offset by a decrease in production in Canada due to the sale of our Canadian properties in April 2009.

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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:

	Nine Months Ended September 30,			
	2009		2008	
(In thousands)	Realized	Unrealized	Realized	Unrealized
Operating Revenues Increase / (Decrease) to Revenue				
Cash Flow Hedges				
Natural Gas Production	**$ 285,453**	**$**	$ (27,766)	$ (1,649)
Crude Oil	**18,597**		(8,731)	
Total Cash Flow Hedges	**304,050**		(36,497)	(1,649)
Other Derivative Financial Instruments				
Natural Gas Basis Swaps		**(418)**		
Total Other Derivative Financial Instruments		**(418)**		
Total Cash Flow Hedges and Other Derivative Financial Instruments	**$ 304,050**	**$ (418)**	$ (36,497)	$ (1,649)

Operating Expenses

Total costs and expenses from operations decreased by $5.2 million in the first nine months of 2009 compared to the same period of 2008. The primary reasons for this fluctuation are as follows:

Depreciation, Depletion and Amortization increased by $32.9 million from the first nine months of 2008 compared to the first nine months of 2009. This is primarily due to the impact on the DD&A rate of higher capital costs and higher natural gas and oil production volumes, including the east Texas acquisition in August 2008.

Brokered Natural Gas Cost decreased by $27.1 million from the first nine months of 2008 compared to the first nine months of 2009. See the preceding table titled Brokered Natural Gas Revenue and Cost for further analysis.

Taxes Other Than Income decreased by $22.2 million from the first nine months of 2008 compared to the first nine months of 2009 due to lower production taxes as a result of lower average natural gas and crude oil prices, partially offset by higher ad valorem taxes.

Exploration expense increased by $12.5 million from the first nine months of 2008 compared to the first nine months of 2009 primarily due to higher charges for idle contract rigs and higher dry hole and geological and geophysical costs.

General and Administrative expenses decreased by $11.7 million from the first nine months of 2008 compared to the first nine months of 2009. This is primarily due to decreased stock compensation expense largely related to a reduction in supplemental employee compensation expense of $15.7 million, partially offset by an increase in performance share award expense of $3.2 million.

Direct Operations expenses increased by $6.5 million from the first nine months of 2008 compared with the first nine months of 2009 primarily due to higher personnel and labor expenses and higher compressor and outside operated properties charges.

Impairment of Unproved Properties increased by $4.0 million from the first nine months of 2008 compared to the first nine months 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, as well as the amortization of undeveloped costs associated with the east Texas acquisition in August 2008.

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Interest Expense, Net

Interest expense, net increased by $21.4 million in the first nine months of 2009 compared to the first nine months of 2008 primarily due to increased interest expense related to the $492 million principal amount of debt we issued in our July and December 2008 private placements. Weighted-average borrowings under our credit facility based on daily balances were approximately $163 million during the first nine months of 2009 compared to approximately $156 million during the first nine months of 2008. The weighted-average effective interest rate on the credit facility decreased to approximately 4.1% during the first nine months of 2009 compared to approximately 5.0% during the first nine months of 2008.

Income Tax Expense

Income tax expense decreased by $31.9 million due to a decrease in our pre-tax income. The effective tax rates for the first nine months of 2009 and 2008 were 35.9% and 36.1%, respectively.

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 September 30, 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 nine months 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 ASC 815. 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 September 30, 2009, we had the following outstanding commodity derivatives:

Commodity	Derivative Type	Weighted-Average Contract Price [1]		Volume		Contract Period	Net Unrealized Gain *(In thousands)*
Derivatives designated as Hedging Instruments under ASC 815							
Natural Gas	Collar	$12.39 / $9.40	per Mcf	11,910	Mmcf	2009	$ 49,893
Natural Gas	Swap	$12.18	per Mcf	4,053	Mmcf	2009	28,128
Natural Gas	Swap	$11.43	per Mcf	19,295	Mmcf	2010	88,284
Crude Oil	Swap	$125.25	per Bbl	92	Mbbl	2009	6,655
Crude Oil	Swap	$125.00	per Bbl	365	Mbbl	2010	18,390
							$ 191,350
Derivatives not qualifying as Hedging Instruments under ASC 815							
Natural Gas	Basis Swap	$(0.27)	per Mcf	16,123	Mmcf	2012	(440)
							$ 190,910

[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 September 30, 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 $0.5 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 nine months of 2009, natural gas price swaps covered 12,026 Mmcf, or 16%, of our first nine months of 2009 gas production at an average price of $12.18 per Mcf.

We had one crude oil price swap covering 273 Mbbl, or 45%, of our first nine 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 nine months of 2009, natural gas price collars covered 35,343 Mmcf, or 48%, of our first nine months 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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Fair Market Value of Financial Instruments

The estimated fair value of financial instruments is the amount at which the instrument could be exchanged currently between willing parties. The carrying amounts reported in the Condensed Consolidated Balance Sheet for cash and cash equivalents, accounts receivable, and accounts payable approximate fair value. The fair value of long-term debt is the estimated cost to acquire the debt, including a credit spread for the difference between the issue rate and the period end market rate. The credit spread is our default or repayment risk. The credit spread (premium or discount) is determined by comparing our fixed-rate notes to new issues (secured and unsecured) and secondary trades of similar size and credit statistics for both public and private debt. The fair value of all of the fixed-rate notes, excluding the credit facility, are based on interest rates currently available to us. The credit facility approximates fair value because this instrument bears interest at rates based on current market rates.

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

Long-Term Debt

	September 30, 2009		December 31, 2008	
(In thousands)	Carrying Amount	Estimated Fair Value	Carrying Amount	Estimated Fair Value
Long-Term Debt	**$ 810,000**	**$ 856,535**	$ 867,000	$ 807,508
Current Maturities	**(20,000)**	**(20,704)**	(35,857)	(35,796)
Long-Term Debt, excluding Current Maturities	**$ 790,000**	**$ 835,831**	$ 831,143	$ 771,712

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 third 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 nine months ended September 30, 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 September 30, 2009 was 4,795,300.

Increase in Authorized Shares

In April 2009, the stockholders of the Company approved an increase in the authorized number of shares of common stock from 120 million to 240 million shares. The Company also decreased the number of shares of Series A Junior Participating Preferred Stock reserved for issuance from 1,200,000 to 800,000. The shares of Series A Junior Participating Preferred Stock are issuable pursuant to the Company s Preferred Stock Purchase Rights Plan.

ITEM 6. Exhibits

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
*101.INS	XBRL Instance Document
*101.SCH	XBRL Taxonomy Extension Schema Document
*101.CAL	XBRL Taxonomy Extension Calculation Linkbase Document
*101.LAB	XBRL Taxonomy Extension Label Linkbase Document
*101.PRE	XBRL Taxonomy Extension Presentation Linkbase Document
*101.DEF	XBRL Taxonomy Extension Definition Linkbase Document

* Furnished, not filed. Users of this data submitted electronically herewith are advised pursuant to Rule 406T of Regulation S-T that this interactive data file is deemed not filed or part of a registration statement or prospectus for purposes of sections 11 or 12 of the Securities Act of 1933, is deemed not filed for purposes of section 18 of the Securities Exchange Act of 1934, and otherwise is not subject to liability under these sections.

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SIGNATURES

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

	CABOT OIL & GAS CORPORATION (Registrant)
October 29, 2009	By: /s/ Dan O. Dinges Dan O. Dinges Chairman, President and Chief Executive Officer (Principal Executive Officer)
October 29, 2009	By: /s/ Scott C. Schroeder Scott C. Schroeder Vice President and Chief Financial Officer (Principal Financial Officer)
October 29, 2009	By: /s/ Henry C. Smyth Henry C. Smyth Vice President, Controller and Treasurer (Principal Accounting Officer)