CABOT OIL & GAS CORP
Form 10-Q
November 03, 2008

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, 2008

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

CABOT OIL & GAS CORPORATION

(Exact name of registrant as specified in its charter)

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

1200 Enclave Parkway, Houston, Texas 77077

(Address of principal executive offices including ZIP Code)

(281) 589-4600

(Registrant s telephone number, including area code)

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

Yes x No ¨

Indicate by check mark whether the registrant 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 27, 2008, there were 103,352,194 shares of Common Stock, Par Value $.10 Per Share, outstanding.

CABOT OIL & GAS CORPORATION

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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, 2008**	**Three Months Ended September 30, 2007**	**Nine Months Ended September 30, 2008**	**Nine Months Ended September 30, 2007**
OPERATING REVENUES				
Natural Gas Production	**$ 200,279**	$ 140,300	**$ 569,527**	$ 431,178
Brokered Natural Gas	**23,855**	15,179	**86,663**	66,357
Crude Oil and Condensate	**20,002**	15,084	**55,089**	39,289
Other	**684**	285	**2,046**	1,429
	244,820	170,848	**713,325**	538,253
OPERATING EXPENSES				
Brokered Natural Gas Cost	**20,891**	13,223	**75,321**	57,973
Direct Operations Field and Pipeline	**24,974**	20,996	**65,101**	57,131
Exploration	**6,413**	8,766	**18,764**	21,243
Depreciation, Depletion and Amortization	**48,895**	37,744	**132,893**	105,401
Impairment of Unproved Properties	**8,512**	5,841	**19,182**	16,150
Impairment of Oil & Gas Properties (Note 2)		4,614		4,614
General and Administrative	**(209)**	9,715	**60,841**	40,960
Taxes Other Than Income	**20,627**	14,379	**56,749**	42,123
	130,103	115,278	**428,851**	345,595
Gain / (Loss) on Sale of Assets		(49)	**401**	12,293
INCOME FROM OPERATIONS	**114,717**	55,521	**284,875**	204,951
Interest Expense and Other	**10,486**	3,921	**22,684**	11,464
Income Before Income Taxes	**104,231**	51,600	**262,191**	193,487
Income Tax Expense	**37,241**	16,147	**94,601**	68,111
NET INCOME	**$ 66,990**	$ 35,453	**$ 167,590**	$ 125,376
Basic Earnings Per Share	**$ 0.65**	$ 0.37	**$ 1.68**	$ 1.29
Diluted Earnings Per Share	**$ 0.64**	$ 0.36	**$ 1.66**	$ 1.28
Weighted Average Common Shares Outstanding	**103,351**	97,068	**99,858**	96,899
Diluted Common Shares (Note 5)	**104,495**	98,439	**100,901**	98,122

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

CABOT OIL & GAS CORPORATION

CONDENSED CONSOLIDATED BALANCE SHEET (Unaudited)

(In thousands, except share amounts)	**September 30, 2008**	**December 31, 2007**
ASSETS		
Current Assets		
Cash and Cash Equivalents	**$ 47,374**	$ 18,498
Accounts Receivable, Net	**115,027**	109,306
Income Taxes Receivable	**33,550**	3,832
Inventories	**52,152**	27,353
Deferred Income Taxes	**42,228**	26,456
Derivative Contracts (Note 7)	**124,268**	12,655
Other Current Assets	**15,895**	23,313
Total Current Assets	**430,494**	221,413
Properties and Equipment, Net (Successful Efforts Method) (Note 2)	**2,935,531**	1,908,117
Deferred Income Taxes	**84,212**	47,847
Derivative Contracts (Note 7)	**69,447**	
Other Assets	**18,422**	31,217
	$ 3,538,106	$ 2,208,594
LIABILITIES AND STOCKHOLDERS EQUITY		
Current Liabilities		
Accounts Payable	**$ 206,037**	$ 173,497
Current Portion of Long-Term Debt	**20,000**	20,000
Deferred Income Taxes	**47,180**	3,930
Income Taxes Payable	**449**	1,391
Derivative Contracts (Note 7)	**2,644**	5,383
Accrued Liabilities	**41,724**	48,065
Total Current Liabilities	**318,034**	252,266
Long-Term Liability for Pension and Postretirement Benefits (Note 10)	**26,229**	26,947
Long-Term Debt (Note 4)	**800,000**	330,000
Deferred Income Taxes	**674,007**	481,770
Other Liabilities	**48,818**	47,354
Commitments and Contingencies (Note 6)		
Stockholders Equity		
Common Stock:		
Authorized 120,000,000 Shares of $0.10 Par Value Issued and Outstanding 103,554,260 Shares and 102,681,468 Shares in 2008 and 2007, respectively	**10,355**	10,268
Additional Paid-in Capital	**670,969**	424,229
Retained Earnings	**880,961**	722,344
Accumulated Other Comprehensive Income / (Loss) (Note 8)	**112,082**	(894)
Less Treasury Stock, at Cost: (Note 12)		
202,200 Shares and 5,204,700 Shares in 2008 and 2007, respectively	**(3,349)**	(85,690)
Total Stockholders Equity	**1,671,018**	1,070,257
	$ 3,538,106	$ 2,208,594

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

CABOT OIL & GAS CORPORATION

CONDENSED CONSOLIDATED STATEMENT OF CASH FLOWS (Unaudited)

(In thousands)	Nine Months Ended September 30, 2008	2007
CASH FLOWS FROM OPERATING ACTIVITIES		
Net Income	**$ 167,590**	$ 125,376
Adjustments to Reconcile Net Income to Cash Provided by Operating Activities:		
Depreciation, Depletion and Amortization	**132,893**	105,401
Impairment of Unproved Properties	**19,182**	16,150
Impairment of Oil & Gas Properties		4,614
Deferred Income Tax Expense	**96,459**	66,930
Gain on Sale of Assets	**(401)**	(12,293)
Exploration Expense	**18,764**	21,243
Unrealized Loss on Derivatives	**1,649**	
Stock-Based Compensation Expense and Other	**10,371**	13,543
Changes in Assets and Liabilities:		
Accounts Receivable, Net	**(9,869)**	33,701
Income Taxes Receivable	**1,650**	251
Inventories	**(24,799)**	(3,205)
Other Current Assets	**7,420**	(2,876)
Other Assets	**5,694**	(24,510)
Accounts Payable and Accrued Liabilities	**11,054**	(33,570)
Income Taxes Payable	**(942)**	8,364
Other Liabilities	**(976)**	16,297
Stock-Based Compensation Tax Benefit	**(11,011)**	(6,857)
Net Cash Provided by Operating Activities	**424,728**	328,559
CASH FLOWS FROM INVESTING ACTIVITIES		
Capital Expenditures	**(558,931)**	(416,354)
Acquisitions	**(605,408)**	(609)
Proceeds from Sale of Assets	**1,150**	5,826
Exploration Expense	**(18,764)**	(21,243)
Net Cash Used in Investing Activities	**(1,181,953)**	(432,380)
CASH FLOWS FROM FINANCING ACTIVITIES		
Increase in Debt	**735,000**	85,000
Decrease in Debt	**(265,000)**	(10,000)
Net Proceeds from Sale of Common Stock	**316,229**	2,314
Stock-Based Compensation Tax Benefit	**11,011**	6,857
Dividends Paid	**(8,973)**	(7,753)
Capitalized Debt Issuance Costs	**(2,166)**	
Net Cash Provided by Financing Activities	**786,101**	76,418
Net Increase / (Decrease) in Cash and Cash Equivalents	**28,876**	(27,403)
Cash and Cash Equivalents, Beginning of Period	**18,498**	41,854
Cash and Cash Equivalents, End of Period	**$ 47,374**	$ 14,451

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

CABOT OIL & GAS CORPORATION

NOTES TO THE CONDENSED CONSOLIDATED FINANCIAL STATEMENTS (Unaudited)

1. FINANCIAL STATEMENT PRESENTATION

During interim periods, Cabot Oil & Gas Corporation (the Company) follows the same accounting policies used in its Annual Report to Stockholders and its Annual Report on Form 10-K for the year ended December 31, 2007 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 Company s 2007 Annual Report to Stockholders and its Annual Report on Form 10-K. In management s opinion, the accompanying interim condensed consolidated financial statements contain all material adjustments, consisting only of normal recurring adjustments, necessary for a fair statement. The results for any interim period are not necessarily indicative of the expected results for the entire year.

With respect to the unaudited financial information of the Company for the three-month and nine-month periods ended September 30, 2008 and 2007, 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 31, 2008 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.

Effective January 1, 2008, the Company adopted those provisions of Statement of Financial Accounting Standards (SFAS) No. 157, Fair Value Measurements, that were required to be adopted. There was no financial statement impact upon adoption on January 1, 2008. For further information regarding the adoption of SFAS No. 157, please refer to Note 7 of the Notes to the Condensed Consolidated Financial Statements.

SFAS No. 159, The Fair Value Option for Financial Assets and Financial Liabilities, including an amendment of FASB Statement No. 115, became effective on January 1, 2008 and permits companies to choose, at specified dates, to measure certain eligible financial instruments at fair value. The provisions of SFAS No. 159 apply only to entities that elect to use the fair value option and to all entities with available-for-sale and trading securities. At the effective date, companies may elect the fair value option for eligible items that exist at that date, and the effect of the first remeasurement to fair value must be reported as a cumulative-effect adjustment to the opening balance of retained earnings. Since the Company has not elected to adopt the fair value option for eligible items, SFAS No. 159 has not had an impact on its financial position or results of operations.

Recently Issued Accounting Pronouncements

In June 2008, the Financial Accounting Standards Board (FASB) issued FASB Staff Position (FSP) No. Emerging Issues Task Force (EITF) 03-6-1, Determining Whether Instruments Granted in Share-Based Payment Transactions Are Participating Securities. Under this FSP, unvested share-based payment awards that contain nonforfeitable rights to dividends or dividend equivalents, whether they are paid or unpaid, are considered participating securities and should be included in the computation of earnings per share pursuant to the two-class method. FSP No. EITF 03-6-1 is 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 should be adjusted retrospectively and early application is not permitted. The Company does not believe that FSP No. EITF 03-6-1 will have a material impact on its financial position, results of operations or cash flows.

In May 2008, the FASB issued SFAS No. 162, The Hierarchy of Generally Accepted Accounting Principles, which identifies a consistent framework for selecting accounting principles to be used in preparing financial statements for nongovernmental entities that are presented in conformity with United

States generally accepted accounting principles (GAAP). The current GAAP hierarchy was criticized due to its complexity, ranking position of FASB Statements of Financial Accounting Concepts and the fact that it is directed at auditors rather than entities. SFAS No. 162 will be effective 60 days following the SEC s approval of the Public Company Accounting Oversight Board amendments to AU Section 411, The Meaning of Present Fairly in Conformity with Generally Accepted Accounting Principles. The FASB does not expect that SFAS No. 162 will have a change in current practice, and the Company does not believe that SFAS No. 162 will have an impact on its financial position, results of operations or cash flows.

In March 2008, the FASB issued SFAS No. 161, Disclosures about Derivative Instruments and Hedging Activities, which amends SFAS No. 133, Accounting for Derivative Instruments and Hedging Activities. Enhanced disclosures to improve financial reporting transparency are required and include disclosure about the location and amounts of derivative instruments in the financial statements, how derivative instruments are accounted for and how derivatives affect an entity s financial position, financial performance and cash flows. 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. SFAS No. 161 is effective for financial statements issued for fiscal years and interim periods beginning after November 15, 2008, with early application and comparative disclosures encouraged, but not required. The Company has not yet adopted SFAS No. 161. The Company does not believe that SFAS No. 161 will have an impact on its financial position, results of operations or cash flows.

In December 2007, the FASB issued SFAS No. 160, Noncontrolling Interest in Consolidated Financial Statements, an amendment of Accounting Research Bulletin (ARB) No. 51. SFAS No. 160 clarifies that a noncontrolling interest (previously commonly referred to as a minority interest) in a subsidiary is an ownership interest in the consolidated entity and should be reported as equity in the consolidated financial statements. The presentation of the consolidated income statement has been changed by SFAS No. 160, and consolidated net income attributable to both the parent and the noncontrolling interest is now required to be reported separately. Previously, net income attributable to the noncontrolling interest was typically reported as an expense or other deduction in arriving at consolidated net income and was often combined with other financial statement amounts. In addition, the ownership interests in subsidiaries held by parties other than the parent must be clearly identified, labeled, and presented in equity in the consolidated financial statements separately from the parent s equity. Subsequent changes in a parent s ownership interest while the parent retains its controlling financial interest in its subsidiary should be accounted for consistently, and when a subsidiary is deconsolidated, any retained noncontrolling equity interest in the former subsidiary must be initially measured at fair value. Expanded disclosures, including a reconciliation of equity balances of the parent and noncontrolling interest, are also required. SFAS No. 160 is effective for fiscal years, and interim periods within those fiscal years, beginning on or after December 15, 2008 and earlier adoption is prohibited. Prospective application is required. At this time, the Company does not have any material noncontrolling interests in consolidated subsidiaries. Therefore, it does not believe that the adoption of SFAS No. 160 will have a material impact on its financial position, results of operations or cash flows.

In December 2007, the FASB issued SFAS No. 141(R), Business Combinations. SFAS No. 141(R) was issued in an effort to continue the movement toward the greater use of fair values in financial reporting and increased transparency through expanded disclosures. It changes how business acquisitions are accounted for and will impact financial statements at the acquisition date and in subsequent periods. Certain of these changes will introduce more volatility into earnings. The acquirer must now record all assets and liabilities of the acquired business at fair value, and related transaction and restructuring costs will be expensed rather than the previous method of being capitalized as part of the acquisition. SFAS No. 141(R) also impacts the annual goodwill impairment test associated with acquisitions, including those that close before the effective date of SFAS No. 141(R). The definitions of a business and a business combination have been expanded, resulting in more transactions qualifying as business combinations. SFAS No. 141(R) is effective for fiscal years, and interim periods within those fiscal years, beginning on or after December 31, 2008 and earlier adoption is prohibited. The Company cannot predict the impact that the adoption of SFAS No. 141(R) will have on its financial position, results of operations or cash flows with respect to any acquisitions completed after December 31, 2008.

2. PROPERTIES AND EQUIPMENT, NET

Properties and equipment, net are comprised of the following:

(In thousands)		September 30, 2008		December 31, 2007
Unproved Oil and Gas Properties	$	**257,114**	$	108,868
Proved Oil and Gas Properties		**3,602,172**		2,627,346
Gathering and Pipeline Systems		**262,248**		235,127
Land, Building and Other Equipment		**65,758**		41,602
		4,187,292		3,012,943
Accumulated Depreciation, Depletion and Amortization		**(1,251,761)**		(1,104,826)
	$	**2,935,531**	$	1,908,117

At September 30, 2008, 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.

During the third quarter of 2008, the Company did not record any impairment of oil and gas properties. During the third quarter of 2007, the Company recorded an impairment of approximately $4.6 million in the Castor field in Bienville Parish, Louisiana in the Gulf Coast region resulting from two non-commercial development completions. This impairment charge was recorded due to the capitalized costs of the field exceeding the future undiscounted cash flows. This charge was reflected in the quarterly operating results of the Company and were measured based on discounted cash flows utilizing a discount rate appropriate for risks associated with the related field.

In April 2008, the Company acquired a services business for total consideration of $21.6 million, comprised of the conversion of a $15.6 million note receivable, the issuance of 70,168 shares of Company common stock, and the payment of $2.5 million in cash. The transaction was accounted for as a business combination, and the Company recorded approximately $4.4 million of goodwill.

East Texas Property Acquisition

On August 15, 2008, the Company completed the acquisition of certain producing oil and gas properties located in Panola and Rusk counties, Texas in order to expand its position in the Minden field. Total net cash consideration paid by the Company in the transaction was approximately $603.7 million, which reflects the total gross purchase price of $604.4 million adjusted by $0.7 million comprised of a $1.7 million decrease for the impact of purchase price adjustments, including adjustments based on each party s share of production proceeds received, expenses paid and capital costs incurred for periods before and after the effective date of the acquisition of May 1, 2008, and a $1.0 million increase for the impact of transaction costs, which were primarily legal and accounting costs. The purchase price is subject to additional post-closing adjustments based on production proceeds received and expenses paid as well as any expenses for title or environmental defects related to the properties that exceed certain deductible amounts.

The $603.7 million purchase price was allocated to Properties and Equipment and Other Liabilities (for the asset retirement obligation) as follows:

(In thousands)	
Proved Oil and Gas Properties [(1)]	$ 528,444
Unproved Oil and Gas Properties	52,897
Gathering and Pipeline Systems	22,814
Total Assets Acquired	**604,155**
Less:	
Asset Retirement Obligations	(460)
	$ 603,695

(1) Proved oil and gas properties were determined by analysis of reserves.

The acquired properties are comprised of approximately 25,000 gross leasehold acres with a 97% average working interest near the Company s existing Minden field. Most of the producing properties were operated by the sellers. In addition, the acquisition included a natural gas gathering infrastructure of 31 miles of pipeline, 5,400 horsepower of compression and four water disposal wells. The Company estimates that proved reserves included in the acquisition were approximately 182 Bcfe as of August 1, 2008 (allocated mainly to the Cotton Valley formation).

The east Texas acquisition was recorded using the purchase method of accounting. Financial results for the period from the closing date on August 15, 2008 to September 30, 2008 are included within the Company s three and nine month periods ended September 30, 2008. The following table presents the unaudited pro forma results of operations for the three and nine months ended September 30, 2008 and 2007, as if the acquisition was made at the beginning of each period. These pro forma results are not necessarily indicative of future results, nor do they purport to represent the actual financial results that would have occurred had the acquisition been in effect for the periods presented.

(In thousands, except per share amounts)	**Three Months Ended September 30, 2008 (Unaudited)**	**Three Months Ended September 30, 2007 (Unaudited)**	**Nine Months Ended September 30, 2008 (Unaudited)**	**Nine Months Ended September 30, 2007 (Unaudited)**
Revenues	**$ 256,900**	$ 175,900	**$ 776,946**	$ 546,998
Net Income	**$ 67,836**	$ 25,926	**$ 172,248**	$ 100,535
Earnings Per Share:				
Basic	**$ 0.66**	$ 0.25	**$ 1.67**	$ 0.99
Diluted	**$ 0.65**	$ 0.25	**$ 1.65**	$ 0.97
Weighted Average Common Shares Outstanding:				
Basic	**103,351**	102,071	**103,071**	101,902
Diluted	**104,495**	103,442	**104,114**	103,125

The Company funded the acquisition with a combination of the net proceeds from its June 2008 sale of approximately five million shares of common stock (see Note 12 of the Notes to the Condensed Consolidated Financial Statements) and the net proceeds from its July 2008 private placement of senior unsecured fixed rate notes (see Note 4 of the Notes to the Condensed Consolidated Financial Statements). Additionally, in order to mitigate the exposure to price fluctuations of natural gas and crude oil, the Company entered into 12 contracts for natural gas price swaps and three contracts for crude oil swaps in the second quarter of 2008 covering production associated with the acquired properties for the second half of 2008 through 2010 (see Note 7 of the Notes to the Condensed Consolidated Financial Statements).

3. ADDITIONAL BALANCE SHEET INFORMATION

Certain balance sheet amounts are comprised of the following:

(In thousands)	**September 30, 2008**	December 31, 2007
ACCOUNTS RECEIVABLE, NET		
Trade Accounts	**$ 101,931**	$ 94,550
Joint Interest Accounts	**16,176**	16,443
Other Accounts	**428**	2,291
	118,535	113,284
Allowance for Doubtful Accounts	**(3,508)**	(3,978)
	$ 115,027	$ 109,306
INVENTORIES		
Natural Gas in Storage	**$ 34,614**	$ 20,472
Tubular Goods and Well Equipment	**16,260**	5,953
Pipeline Imbalances	**1,278**	928
	$ 52,152	$ 27,353
OTHER CURRENT ASSETS		
Drilling Advances	**$ 4,509**	$ 2,475
Prepaid Balances	**11,386**	8,900
Restricted Cash		11,600
Other Accounts		338
	$ 15,895	$ 23,313
OTHER ASSETS		
Note Receivable	**$**	$ 13,375
Goodwill	**4,409**	
Rabbi Trust Deferred Compensation Plan	**9,899**	9,744
Other Accounts	**4,114**	8,098
	$ 18,422	$ 31,217
ACCOUNTS PAYABLE		
Trade Accounts	**$ 36,204**	$ 27,678
Natural Gas Purchases	**11,900**	6,465
Royalty and Other Owners	**49,997**	37,023
Capital Costs	**86,398**	83,754
Taxes Other Than Income	**10,501**	6,416
Drilling Advances	**1,170**	1,528
Wellhead Gas Imbalances	**3,349**	3,227
Other Accounts	**6,518**	7,406
	$ 206,037	$ 173,497
ACCRUED LIABILITIES		
Employee Benefits	**$ 9,004**	$ 13,699
Current Liability for Pension Benefits	**116**	116

Current Liability for Postretirement Benefits		**642**		642
Taxes Other Than Income		**19,195**		13,216
Interest Payable		**9,946**		6,518
Litigation				11,600
Other Accounts		**2,821**		2,274
	$	**41,724**	$	48,065
OTHER LIABILITIES				
Rabbi Trust Deferred Compensation Plan	**$**	**17,204**	$	16,018
Accrued Plugging and Abandonment Liability		**27,105**		24,724
Derivative Contracts		**315**		
Other Accounts		**4,194**		6,612
	$	**48,818**	$	47,354

4. LONG-TERM DEBT

At September 30, 2008, the Company had $185 million of borrowings outstanding under its revolving credit facility at a weighted-average interest rate of 4.4%. The credit facility provides for an available credit line of $350 million. In June 2008, the Company amended its revolving credit facility agreement to increase the commitments of the lenders to $350 million from $250 million pursuant to the accordion feature in the agreement. The term of the credit facility expires in December 2009. The credit facility is unsecured. The available credit line is subject to adjustment from time to time on the basis of the projected present value (as determined by the banks petroleum engineer) of estimated future net cash flows from certain proved oil and gas reserves and other assets of the Company. While the Company does not expect a reduction in the available credit line, in the event that it is adjusted below the outstanding level of borrowings, the Company has a period of six months either to reduce its outstanding debt to the adjusted credit line available with a requirement to provide additional borrowing base assets or to pay down one-sixth of the excess during each of the six months.

In addition to borrowings under the credit facility, the Company had the following debt outstanding at September 30, 2008:

- $40 million of 12-year 7.19% Notes due in November 2009, which consisted of $20 million of long-term debt and $20 million of current portion of long-term debt, to be repaid in two remaining annual installments of $20 million in November of each year
- $75 million of 10-year 7.26% Notes due in July 2011
- $75 million of 12-year 7.36% Notes due in July 2013
- $20 million of 15-year 7.46% Notes due in July 2016
- $245 million of 10-year 6.44% Notes due in July 2018
- $100 million of 12-year 6.54% Notes due in July 2020
- $80 million of 15-year 6.69% Notes due in July 2023

The revolving credit facility includes a covenant limiting the Company s total debt. In conjunction with the June 2008 amendment of the Company s revolving credit facility, the Company s total debt limit was increased from $610 million to $1.2 billion.

On July 16, 2008, the Company completed a private placement of $425 million aggregate principal amount of senior unsecured fixed-rate notes (collectively, the New Notes) pursuant to a note purchase agreement dated July 16, 2008. The New Notes are shown in the borrowings detail discussed above and consist of the amounts due in July 2018, 2020 and 2023.

Interest on the New Notes of each series is payable semi-annually. The Company may prepay all or any portion of the New Notes of each series on any date at a price equal to the principal amount thereof plus accrued and unpaid interest and a make-whole premium. The New Notes contain restrictions on the merger of the Company with a third party other than under certain limited conditions. There are also various other restrictive covenants customarily found in such debt instruments. These covenants include a required asset coverage ratio (present value of proved reserves plus adjusted cash (as defined in the note purchase agreement) to debt and other liabilities) of at least 1.5 to 1.0, and a minimum annual coverage ratio of operating cash flow to interest expense for the trailing four quarters of 2.8 to 1.0. The New Notes also are subject to customary events of default. The Company is required to offer to prepay the New Notes upon specified change in control events accompanied by a ratings decline below investment grade.

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

5. EARNINGS PER COMMON SHARE

Basic earnings per common share (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, 2008 and 2007:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2008	**2007**	**2008**	**2007**
Weighted-Average Shares Basic	**103,351,147**	97,067,586	**99,857,606**	96,898,663
Dilution Effect of Stock Options and Awards at End of Period	**1,144,096**	1,371,747	**1,043,650**	1,223,609
Weighted-Average Shares Diluted	**104,495,243**	98,439,333	**100,901,256**	98,122,272
Weighted-Average Stock Awards and Shares Excluded from Diluted Earnings per Share due to the Anti-Dilutive Effect		143,613	**149,524**	331,996

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.

West Virginia Royalty Litigation

In December 2001, the Company was sued by two royalty owners in West Virginia state court for an unspecified amount of damages. The plaintiffs requested class certification and alleged that the Company failed to pay royalty based upon the wholesale market value of the gas, that the Company had taken improper deductions from the royalty and that it failed to properly inform royalty owners of the deductions. The plaintiffs also claimed that they are entitled to a 1/8th royalty share of the gas sales contract settlement that the Company reached with Columbia Gas Transmission Corporation in 1995 bankruptcy proceedings. The Court entered an order on June 1, 2005 granting the motion for class certification.

The parties reached a tentative settlement pursuant to which the Company paid a total of $12.0 million into a trust fund for disbursement to the class members upon final approval of the settlement by the Court. The court held the final fairness hearing on February 12, 2008 and approved the settlement, authorized the distribution of the funds to the class members and dismissed all claims against the Company with prejudice. These funds were disbursed in April 2008. Prior to the date of the Court s final order approving the settlement, these restricted cash funds were held by a financial institution in West Virginia under the joint custody of the plaintiffs and the Company. The Company had provided a reserve sufficient to cover the amount agreed upon to settle this litigation. As of June 30, 2008, these funds had been paid out to the class members or were controlled by the Court. Accordingly, the Company had reduced Other Current Assets in the Condensed Consolidated Balance Sheet. In the settlement, the Company and the class members also agreed to a methodology for payment of future royalties and the reporting format such methodology will take.

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 $1.3 million of additional loss with respect to those matters in which reserves have been established. Future changes in the facts and circumstances could result in the actual liability exceeding the estimated ranges of loss and amounts accrued.

While the outcome and impact on the Company cannot be predicted with certainty, management believes that the resolution of these proceedings through settlement or adverse judgment will not have a material adverse effect on the condensed consolidated financial position or cash flow of the Company. Operating results, however, could be significantly impacted in the reporting periods in which such matters are resolved.

Firm Gas Transportation Agreements

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

As previously disclosed in the Company s Annual Report on Form 10-K for the year ended December 31, 2007 (the Form 10-K), obligations under firm gas transportation agreements in effect at December 31, 2007 were $82.2 million. As of September 30, 2008, obligations under firm gas transportation agreements were $75.8 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 commitments on five drilling rigs under contract in the Gulf Coast for a total commitment of $71.3 million. During 2008, one of these rigs was released, reducing the Company s 2008 commitment by $6.2 million. In addition, during the first nine months of 2008, the Company entered into new commitments for seven additional drilling rigs. As of September 30, 2008, the total commitment for 11 drilling rigs was $81.7 million, comprised of commitments for the fourth quarter of 2008 of $38.7 million and commitments for 2009 and 2010 of $40.8 million and $2.2 million, respectively. 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

Adoption of SFAS No. 157

In September 2006, the FASB issued SFAS No. 157, Fair Value Measurements, which establishes a formal framework for measuring fair values of assets and liabilities in financial statements that are already required by United States generally accepted accounting principles to be measured at fair value. SFAS No. 157 clarifies guidance in FASB Concepts Statement (CON) No. 7 which discusses present value techniques in measuring fair value. Additional disclosures are also required for transactions measured at fair value. SFAS No. 157 is effective for fiscal years beginning after November 15, 2007, and interim periods within those fiscal years. In February 2008, the FASB issued FSP No. FAS 157-2, Effective Date of FASB Statement No. 157, which granted a one year deferral (to fiscal years beginning after November 15, 2008, and interim periods within those fiscal years) for certain non-financial assets and liabilities to comply with SFAS No. 157. The Company will adopt the provisions of FAS No. 157 covered under FSP No. 157-2 on January 1, 2009. The Company is currently evaluating the impact of implementation with respect to nonfinancial assets and liabilities measured on a nonrecurring basis on its consolidated financial statements, which will primarily be limited to asset impairments including goodwill, other long-lived assets, asset retirement obligations and assets acquired and liabilities assumed in a business combination, if any. Additionally, in February 2008, the FASB issued FSP No. FAS 157-1, Application of FASB Statement No. 157 to FASB Statement No. 13 and Other Accounting Pronouncements That Address Fair Value Measurements for Purposes of Lease Classification or Measurement under Statement 13, which amends SFAS No. 157 to exclude SFAS No. 13 and related pronouncements that address fair value measurements for purposes of lease classification and measurement. FSP No. FAS 157-1 is effective upon the initial adoption of SFAS No. 157. The Company has adopted SFAS No. 157 and FSP No. FAS 157-1 discussed above, and there was no impact on its financial position or results of operations for the nine months ended September 30, 2008.

In October 2008, the FASB issued FSP No. FAS 157-3, Estimating the Fair Value of a Financial Asset in a Market That Is Not Active to amend SFAS No.157 to provide guidance regarding how to determine the fair value of a financial asset when there is no active market for the asset at the measurement date. FSP No. FAS 157-3 clarifies how management s internal assumptions, such as internal cash flow and discount rate assumptions, should be considered in measuring fair value when observable data are not present. In addition, observable market information from an inactive market should be considered to determine fair value, and it is inappropriate to conclude that all market activity represents forced liquidations or distressed sales or to conclude that any transaction price can determine fair value. The use of broker quotes and pricing services should also be considered to assess the relevance of observable and unobservable data. When valuing financial assets, significant judgment is required. FSP No. FAS 157-3 is effective upon issuance and has been considered in conjunction with the Company s third quarter 2008 financial reporting and results. There was no material impact on its financial position or results of operations for the nine months ended September 30, 2008.

As defined in SFAS No. 157, fair value is the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date (exit price). The transaction is based on a hypothetical transaction in the principal or most advantageous market considered from the perspective of the market participant that holds the asset or owes the liability.

The valuation techniques that can be used under SFAS No. 157 are the market approach, income approach or cost approach. The market approach uses prices and other information for market transactions involving identical or comparable assets or liabilities, such as matrix pricing. The income approach uses valuation techniques to convert future amounts to a single discounted present value amount based on current market conditions about those future amounts, such as present value techniques, option pricing models (i.e. Black-Scholes model) and binomial models (i.e. Monte-Carlo model). The cost approach is based on current replacement cost to replace an asset.

The Company utilizes market data or assumptions that market participants who are independent, knowledgeable and willing and able to transact would use in pricing the asset or liability, including assumptions about risk and the risks inherent in the inputs to the valuation technique. These inputs can be readily observable, market corroborated or generally unobservable. The Company attempts to utilize valuation techniques that maximize the use of observable inputs and minimize the use of unobservable inputs. The Company is able to classify fair value balances based on the observability of those inputs. SFAS No. 157 establishes a formal fair value hierarchy based on the inputs used to measure fair value. The hierarchy gives the highest priority to level 1 measurements and the lowest priority to level 3 measurements, and accordingly, level 1 measurements should be used whenever possible.

The three levels of the fair value hierarchy as defined by SFAS No. 157 are as follows:

Level 1: Valuations utilizing quoted, unadjusted prices for identical assets or liabilities in active markets that the Company has the ability to access. This is the most reliable evidence of fair value and does not require a significant degree of judgment. Examples include exchange-traded derivatives and listed equities that are actively traded.

Level 2: Valuations utilizing quoted prices in markets that are not considered to be active or financial instruments for which all significant inputs are observable, either directly or indirectly for substantially the full term of the asset or liability. Financial instruments that are valued using models or other valuation methodologies are included. Models used should primarily be industry-standard models that consider various assumptions and economic measures, such as interest rates, yield curves, time value, volatilities, contract terms, current market prices, credit risk or other market-corroborated inputs. Examples include most over-the-counter derivatives (non-exchange traded), physical commodities, most structured notes and municipal and corporate bonds.

Level 3: Valuations utilizing significant, unobservable inputs. This provides the least objective evidence of fair value and requires a significant degree of judgment. Inputs may be used with internally developed methodologies and should reflect an entity s assumptions using the best information available about the assumptions that market participants would use in pricing an asset or liability. Examples include certain corporate loans, real-estate and private equity investments and long-dated or complex over-the-counter derivatives.

Depending on the particular asset or liability, input availability can vary depending on factors such as product type, longevity of a product in the market and other particular transaction conditions. In some cases, certain inputs used to measure fair value may be categorized into different levels of the fair value hierarchy. For disclosure purposes under SFAS No. 157, the lowest level that contains significant inputs used in valuation should be chosen. Per SFAS No. 157, the Company has classified its assets and liabilities into these levels depending upon the data relied on to determine the fair values. The fair values of the Company s natural gas and crude oil price collars and swaps are designated as Level 3.

The following fair value hierarchy table presents information about the Company s assets and liabilities measured at fair value on a recurring basis as of September 30, 2008:

(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, 2008**
Assets				
Rabbi Trust Deferred Compensation Plan	$ 9,899	$	$	**$ 9,899**
Derivative Contracts			193,715	**193,715**
Total Assets	$ 9,899	$	$ 193,715	**$ 203,614**
Liabilities				
Rabbi Trust Deferred Compensation Plan	$ (17,204)	$	$	**$ (17,204)**
Derivative Contracts			(2,959)	**(2,959)**
Total Liabilities	$ (17,204)	$	$ (2,959)	**$ (20,163)**

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

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

(In thousands)	Three Months Ended September 30, 2008	Nine Months Ended September 30, 2008
Balance as of beginning of period	$ (282,771)[1]	$ 7,272[2]
Total Gains or (Losses) (Realized or Unrealized):		
Included in Earnings	(8,799)	(38,147)
Included in Other Comprehensive Income	472,268	185,133
Purchases, Issuances and Settlements	10,058	36,498
Transfers In and/or Out of Level 3		
Balance as of end of period	**$ 190,756**	**$ 190,756**

(1) Net derivatives for Level 3 at June 30, 2008 included derivative liabilities of $282.8 million.

(2) Net derivatives for Level 3 at December 31, 2007 included derivative assets of $12.7 million and derivative liabilities of $5.4 million.

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. Although the Company utilizes multiple quotes to assess the reasonableness of its values, the Company has not attempted to obtain sufficient corroborating market evidence to support classifying these derivative contracts as Level 2. The Company measured the nonperformance risk of its counterparties by reviewing credit default swap spreads for the various financial institutions in which it has derivative transactions. The resulting reduction to the net receivable derivative contract position was $9.4 million. In times where the Company has net derivative contract liabilities, the nonperformance risk of the Company is evaluated using a market credit spread provided by the Company s bank.

Rabbi Trust Deferred Compensation Plan

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. As of September 30, 2008, 256,400 shares of the Company s stock representing vested performance share awards were deferred into the rabbi trust. For the first nine months of 2008, a reduction to the rabbi trust deferred compensation liability of $1.5 million was recognized, representing the decrease in the closing price of all shares from December 31, 2007 to September 30, 2008. This reduction in stock-based compensation expense was included in General and Administrative expense in the Condensed Consolidated Statement of Operations.

Derivative Instruments and Hedging Activity

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. At September 30, 2008, the Company had 55 cash flow hedges open: 36 natural gas price collar arrangements, 15 natural gas swap arrangements, three crude oil swap arrangements and one crude oil collar arrangement. At September 30, 2008, a $192.4 million ($121.0 million, net of tax) unrealized gain was recorded in Accumulated Other Comprehensive Income / (Loss), along with a $124.3 million short-term derivative receivable, a $69.4 million long-term derivative receivable, a $2.6 million short-term derivative payable and a $0.3 million long-term derivative payable (included within other long-term liabilities in the Condensed Consolidated Balance Sheet). In addition, a $1.6 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, 2008.

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

During the first nine months of 2008, the Company entered into 24 new natural gas collar contracts covering a portion of its 2008 and 2009 production and 12 new natural gas price swap contracts covering a portion of its 2008, 2009 and 2010 production. As of September 30, 2008, natural gas price collars for the three months ending December 31, 2008 will cover 14,775 Mmcf of production at a weighted-average floor of $8.59 per Mcf and a weighted-average ceiling of $10.83 per Mcf. As of September 30, 2008, natural gas price collars for the twelve months ending December 31, 2009 will cover 47,253 Mmcf of production at a weighted-average floor of $9.40 per Mcf and a weighted-average ceiling of $12.39 per Mcf. Natural gas price swaps for the three months ending December 31, 2008 will cover 3,678 Mmcf of production at a weighted-average price of $11.22 per Mcf. As of September 30, 2008, natural gas price swaps for the years ending December 31, 2009 and 2010 will cover 16,079 Mmcf and 19,295 Mmcf of production, respectively, at a weighted-average price of $12.18 per Mcf and $11.43 per Mcf, respectively.

During the first nine months of 2008, the Company also entered into three new crude oil price swaps covering a portion of its 2008, 2009 and 2010 production. As of September 30, 2008, a crude oil price swap for the three months ending December 31, 2008 will cover 46 Mbbls at a fixed price of $127.15 per Bbl. Crude oil price swaps for the years ending December 31, 2009 and 2010 will cover 365 Mbbls each at a fixed price of $125.25 per Bbl and $125.00 per Bbl, respectively.

During the second quarter of 2008, in anticipation of the east Texas acquisition, the Company entered into 12 contracts for natural gas price swaps and three contracts for crude oil swaps (included in the amounts discussed above) for the remainder of 2008 and extending through 2010 for the purpose of reducing commodity price risk associated with anticipated production after the transaction closing. Under SFAS No. 133, forecasted transactions associated with an acquisition do not qualify for hedge accounting. Accordingly, in the second quarter of 2008, the Company designated a portion of certain volumes of the hedge transactions as hedges of current production. A portion of one hedge transaction did not qualify for hedge accounting. During the second quarter of 2008, a $2.7 million unrealized loss representing the mark to market change on this portion of the hedge was recorded in the Condensed Consolidated Statement of Operations as a component of Natural Gas Production Revenue. The remaining hedge transactions were substantially deemed to be 100% effective, resulting in ineffectiveness totaling $0.2 million which was recorded in the Condensed Consolidated Statement of Operations in the second quarter of 2008. During the third quarter of 2008, subsequent to the closing of the east Texas acquisition, the Company was able to designate all of the transactions as hedges. In connection with the scheduled settlements during the third quarter of 2008, approximately $1.3 million of the previously recognized $2.9 million unrealized loss was reversed, leaving a $1.6 million unrealized loss as a component of Natural Gas Production Revenue in the Condensed Consolidated Statement of Operations for the nine months ended September 30, 2008. The Company uses regression analysis to assess hedge effectiveness and the hypothetical derivative method in measuring the amount of ineffectiveness, if any. During the nine months ended September 30, 2007, there was no ineffectiveness recorded in the Condensed Consolidated Statement of Operations.

Based upon estimates at September 30, 2008, the Company would expect to reclassify to the Condensed Consolidated Statement of Operations over the next 12 months $77.5 million in after-tax income associated with its commodity hedges. This reclassification represents the net short-term receivable associated with open positions currently not reflected in earnings at September 30, 2008 related to anticipated 2008 and 2009 production.

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, 2008 and 2007:

	Three Months Ended September 30,					
(In thousands)		**2008**			**2007**	
Accumulated Other Comprehensive Income / (Loss) Beginning of Period			**$ (182,602)**			$ 14,051
Net Income		**$ 66,990**			$ 35,453	
Other Comprehensive Income / (Loss), net of taxes:						
Reclassification Adjustment for Settled Contracts, net of taxes of $(3,758) and $10,917, respectively		**6,300**			(17,966)	
Changes in Fair Value of Hedge Positions, net of taxes of $(171,149) and $(7,144), respectively		**291,061**			11,756	
Defined Benefit Pension and Postretirement Plans:						
Amortization of Net Obligation at Transition, net of taxes of $(58) and $(60), respectively	**$ 100**			$ 98		
Amortization of Prior Service Cost, net of taxes of $(93) and $(103), respectively	**158**			170		
Amortization of Net Loss, net of taxes of $(152) and $(122), respectively	**254**	**512**		200	468	
Foreign Currency Translation Adjustment, net of taxes of $1,864 and $(2,456), respectively		**(3,189)**			4,042	
Total Other Comprehensive Income / (Loss)		**294,684**	**294,684**		(1,700)	(1,700)
Comprehensive Income		**$ 361,674**			$ 33,753	
Accumulated Other Comprehensive Income End of Period			**$ 112,082**			$ 12,351

(In thousands)	Nine Months Ended September 30, 2008			2007		
Accumulated Other Comprehensive Income / (Loss) - Beginning of Period			**$ (894)**			$ 37,160
Net Income		**$ 167,590**			$ 125,376	
Other Comprehensive Income / (Loss), net of taxes:						
Reclassification Adjustment for Settled Contracts, net of taxes of $(13,541) and $22,598, respectively		**22,957**			(37,186)	
Changes in Fair Value of Hedge Positions, net of taxes of $(55,122) and $(2,035), respectively		**93,513**			2,699	
Defined Benefit Pension and Postretirement Plans:						
Amortization of Net Obligation at Transition, net of taxes of $(175) and $(179), respectively	**$ 299**			$ 295		
Amortization of Prior Service Cost, net of taxes of $(279) and $(310), respectively	**473**			510		
Amortization of Net Loss, net of taxes of $(452) and $(364), respectively	**766**	**1,538**		598	1,403	
Foreign Currency Translation Adjustment, net of taxes of $3,033 and $(5,029), respectively		**(5,032)**			8,275	
Total Other Comprehensive Income / (Loss)		**112,976**	**112,976**		(24,809)	(24,809)
Comprehensive Income		**$ 280,566**			$ 100,567	
Accumulated Other Comprehensive Income - End of Period			**$ 112,082**			$ 12,351

Changes in the components of accumulated other comprehensive income / (loss), net of taxes, for the nine months ended September 30, 2008 were as follows:

Accumulated Other Comprehensive Income / (Loss), net of taxes *(In thousands)*	**Net Gains / (Losses) on Cash Flow Hedges**	**Defined Benefit Pension and Postretirement Plans**	**Foreign Currency Translation Adjustment**	**Total**
Balance at December 31, 2007	$ 4,553	$ (14,027)	$ 8,580	$ (894)
Net change in unrealized gain on cash flow hedges, net of taxes of $(68,663)	116,470			116,470
Net change in defined benefit pension and postretirement plans, net of taxes of $(906)		1,538		1,538
Change in foreign currency translation adjustment, net of taxes of $3,033			(5,032)	(5,032)
Balance at September 30, 2008	**$ 121,023**	**$ (12,489)**	**$ 3,548**	**$ 112,082**

9. ASSET RETIREMENT OBLIGATIONS

The following table reflects the changes in the asset retirement obligations during the nine months ended September 30, 2008:

(In thousands)	
Carrying amount of asset retirement obligations at December 31, 2007	$ 24,724
Liabilities added during the current period	1,562
Liabilities settled and divested during the current period	(60)
Current period accretion expense	879
Carrying amount of asset retirement obligations at September 30, 2008	**$ 27,105**

Accretion expense was $0.9 million and $0.8 million, respectively, for the nine months ended September 30, 2008 and 2007 and is included within Depreciation, Depletion and Amortization expense on the Company s Condensed Consolidated Statement of Operations.

10. PENSION AND OTHER POSTRETIREMENT BENEFITS

The components of net periodic benefit costs for the three and nine months ended September 30, 2008 and 2007 were as follows:

	Three Months Ended		**Nine Months Ended**	
(In thousands)	**September 30, 2008**	**September 30, 2007**	**September 30, 2008**	**September 30, 2007**
Qualified and Non-Qualified Pension Plans				
Current Period Service Cost	**$ 828**	$ 733	**$ 2,485**	$ 2,199
Interest Cost	**818**	692	**2,454**	2,076
Expected Return on Plan Assets	**(884)**	(754)	**(2,651)**	(2,262)
Amortization of Prior Service Cost	**13**	36	**38**	108
Amortization of Net Loss	**294**	272	**881**	816
Net Periodic Pension Cost	**$ 1,069**	$ 979	**$ 3,207**	$ 2,937
Postretirement Benefits Other than Pension Plans				
Current Period Service Cost	**$ 271**	$ 211	**$ 812**	$ 646
Interest Cost	**345**	273	**1,035**	812
Amortization of Prior Service Cost	**238**	238	**714**	714
Amortization of Net Loss	**112**	55	**336**	152
Amortization of Net Obligation at Transition	**158**	158	**474**	474
Total Postretirement Benefit Cost	**$ 1,124**	$ 935	**$ 3,371**	$ 2,798

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 2008; however, in September 2008 it chose to fund $5 million into the qualified plan. The Company previously disclosed in its financial statements for the year ended December 31, 2007 that it expected to contribute $0.1 million to its non-qualified pension plan and approximately $0.7 million to the postretirement benefit plan during 2008. It is anticipated that these contributions will be made prior to December 31, 2008.

11. STOCK-BASED COMPENSATION

Incentive Plans

Under the Company s 2004 Incentive Plan, incentive and non-statutory stock options, stock appreciation rights (SARs), stock awards, cash awards and performance awards may be granted to key employees, consultants and officers of the Company. Non-employee directors of the Company may be granted discretionary awards under the 2004 Incentive Plan consisting of stock options or stock awards. In the first quarter of 2007, the Board of Directors eliminated the automatic award of an option to purchase 30,000 shares of common stock on the date the non-employee directors first join the Board of Directors. In its place, the Board of Directors considers an annual fixed dollar stock award which is competitive with the Company s peer group. A total of 5,100,000 shares of common stock may be issued under the 2004 Incentive Plan. Under the 2004 Incentive Plan, no more than 1,800,000 shares may be used for stock awards that are not subject to the achievement of performance based goals, and no more than 3,000,000 shares may be issued pursuant to incentive stock options.

Stock-Based Compensation Expense

Compensation expense charged against income for stock-based awards (including the supplemental employee incentive plans) during the first nine months of 2008 and 2007 was $29.6 million and $12.7 million, pre-tax, respectively, and is included in General and Administrative Expense in the Condensed Consolidated Statement of Operations. Stock-based compensation expense in the third quarter of 2008 was a credit of $9.6 million compared to a charge of $1.9 million in the third quarter of 2007. The third quarter 2008 credits primarily relate to a reduction in the liability associated with the value of performance shares in the Company s rabbi trust due to a decline in the Company s stock price, as well as a reduction in the Company s performance share liability related to the expected payout of future performance share awards in which the Company is ranked against its peers.

As disclosed in the Form 10-K, the Company realized an $11.2 million tax benefit for the 2007 tax deduction in excess of book compensation cost related to employee stock-based compensation. In accordance with SFAS No. 123(R), the Company is able to recognize this tax benefit only to the extent it reduces the Company s income taxes payable. Such income tax benefit related to the stock-based compensation was recorded in the third quarter of 2008 as the Company decided to carry back the net operating losses concurrent with the 2007 tax return filing.

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

Restricted Stock Awards

Restricted stock awards vest either at the end of a three year service period, or on a graded-vesting basis of one-third at each anniversary date over a three year service period. Under the graded-vesting approach, the Company recognizes compensation cost over the three year requisite service period for each separately vesting tranche as though the awards are, in substance, multiple awards. For awards that vest at the end of the three year service period, expense is recognized ratably using a straight-line expensing approach over three years. For all restricted stock awards, vesting is dependant upon the employees continued service with the Company, with the exception of employment termination due to death, disability or retirement.

The fair value of restricted stock grants is based on the average of the high and low stock price on the grant date. The maximum contractual term is three years. In accordance with SFAS No. 123(R), the Company accelerated the vesting period for retirement-eligible employees for purposes of recognizing compensation expense in accordance with the vesting provisions of the Company s stock-based compensation programs for awards issued after the adoption of SFAS No. 123(R). The Company used an annual forfeiture rate ranging from 0% to 7.2% based on approximately ten years of the Company s history for this type of award to various employee groups.

There were no restricted stock awards granted during the first nine months of 2008. During the nine months ended September 30, 2008, 400,254 restricted stock awards vested with a weighted-average grant date per share value of $16.23. Compensation expense recorded for all unvested restricted stock awards for the first nine months of 2008 and 2007 was $1.2 million and $2.6 million, respectively. Compensation expense recorded for all unvested restricted stock awards for the third quarter of 2008 and 2007 was $0.2 million and $0.8 million, respectively.

Restricted Stock Units

Restricted stock units are granted from time to time to non-employee directors of the Company. 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.

During the nine months ended September 30, 2008, 16,565 restricted stock units were granted with a grant date per share value of $49.17, and 19,602 restricted stock units were issued to a retiring director with a weighted-average grant date per share value of $26.02. The compensation cost, which reflects the total fair value of these units, recorded in the first nine months of 2008 was $0.8 million. During the first nine months of 2007, the Company recorded $0.9 million of expense related to restricted stock units. No expense was recorded in either the third quarter of 2008 or 2007.

Stock Appreciation Rights

During the first nine months of 2008, the Compensation Committee granted 119,130 SARs to employees. These awards allow the employee to receive any intrinsic value over the $48.48 grant date fair market value that may result from the price appreciation on a set number of common shares during the contractual term of seven years. All of these awards have graded-vesting features and will vest over a service period of three years, with one-third of the award becoming exercisable each year on the anniversary date of the grant. 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, 2008
Weighted-Average Value per Stock Appreciation Right	
Granted During the Period[1]	$ 15.18
Assumptions	
Stock Price Volatility	34.4%
Risk Free Rate of Return	2.8%
Expected Dividend	0.2%
Expected Term (in years)	4.25

[1] Calculated using the Black-Scholes fair value based method.

Compensation expense recorded during the first nine months of 2008 and 2007 for SARs was $1.5 million and $1.3 million, respectively. Included in these amounts were $0.5 million in each period related to the immediate expensing of shares granted in 2008 and 2007 to retirement-eligible employees. Compensation expense in each of the third quarters of 2008 and 2007 was $0.3 million.

Performance Share Awards

During 2008, the Compensation Committee granted three types of performance share awards to employees for a total of 383,065 performance shares. The performance period for two of the three types of these awards commenced on January 1, 2008 and ends December 31, 2010. Both of these awards vest at the end of the three year performance period.

Awards totaling 101,830 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 $41.53. 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 191,400 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 $48.48. 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, 2008, it is currently considered probable that these three criteria will be met.

The third type of performance share award, totaling 89,835 performance shares, with a grant date per share value of $48.48, has a three-year graded vesting schedule, vesting one-third on each anniversary date following the date of grant, provided that the Company has positive operating income for the year preceding the vesting date. If the Company does not have positive operating income 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, 2008, it is currently considered probable that this performance metric will be met.

For all performance share awards granted to employees in 2008 and 2007, an annual forfeiture rate ranging from 0% to 4.5% has been assumed based on the Company s history for this type of award to various employee groups.

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

The three primary inputs for the Monte Carlo model are the risk-free rate, volatility of returns and correlation in movement of total shareholder return. The risk-free rate was generated from the Federal Reserve website for constant maturity treasuries for six-month, one, two and three year bonds and is set equal to the yield, for the period over the remaining duration of the performance period, on treasury securities as of the reporting date. Volatility was set equal to the annualized daily volatility measured over a historic four year 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 58% to approximately 83% for the Company and its peer group. 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, 2008 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 is not marked to market.

	September 30, 2008
Risk Free Rate of Return	0.9% - 2.1%
Stock Price Volatility	43.4% - 54.7%
Expected Dividend	0.3%

The Monte Carlo value per share for the liability component for all outstanding market condition performance share awards ranged from $5.15 to $10.69 at September 30, 2008. The long-term liability for all market condition performance share awards, included in Other Liabilities in the Condensed Consolidated Balance Sheet, at September 30, 2008 and December 31, 2007 was $0.5 million and $0.2 million, respectively. The short-term liability, included in Accrued Liabilities in the Condensed Consolidated Balance Sheet, at September 30, 2008 and December 31, 2007, for certain market condition performance share awards was $1.0 million and $5.5 million, respectively.

During the first nine months of 2008, 238,590 performance shares vested. Of these vested shares, 207,800 shares were granted in 2005 and were market condition awards which provided that employees may receive an aggregate of up to 100% 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. As a result of the Company s ranking on the vesting date, 100% of the shares were paid in common stock and an additional 67% of the fair market value of each share of common stock, or $7.9 million, was paid in cash during the second quarter of 2008. The remaining 30,790 shares that vested in the first nine months of 2008 represent one-third of the three-year graded vesting schedule performance share awards granted in 2007 with a grant date per share value of $35.22. These awards met the performance criteria that the Company had positive operating income for the 2007 year.

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 (discussed above in Note 7 of the Notes to the Condensed Consolidated Financial Statements) during the nine months ended September 30, 2008 and 2007 was $10.3 million and $7.7 million, respectively. Total compensation amounts recognized for all performance share awards as well as amounts related to the shares deferred into the rabbi trust during the quarters ended September 30, 2008 and 2007 were a credit of $10.2 million and an expense of $0.8 million, respectively.

Supplemental Employee Incentive Plans

On January 16, 2008, the Company s Board of Directors adopted a Supplemental Employee Incentive Plan. The plan is intended to provide a compensation tool tied to stock market value creation to serve as an incentive and retention vehicle for full-time non-officer employees by providing for cash payments in the event the Company s common stock reaches a specified trading price.

The bonus payout is triggered if, for any 20 trading days (which need not be consecutive) that fall within a period of 60 consecutive trading days occurring on or before November 1, 2011, the closing price per share of the Company s common stock equals or exceeds the price goal of $60 per share. In such event, the 20th trading day on which such price condition is attained is the Final Trigger Date. The price goal is subject to adjustment by the Compensation Committee to reflect any stock splits, stock dividends or extraordinary cash distributions to stockholders. Under the plan, each eligible employee will receive a minimum distribution of 50% of his or her base salary as of the Final Trigger Date, as adjusted for persons hired after December 31, 2007 to reflect calendar quarters of service, reduced by any interim distribution previously paid to such employee upon the achievement of the interim price goal discussed below. The Committee may, in its discretion, allocate to eligible employees additional distributions, subject to limitations of the plan.

The plan also provides that an interim distribution will be paid to eligible employees upon achieving the interim price goal of $50 per share prior to December 31, 2009. Interim distributions are determined as described above except that interim distributions will be based on 10%, rather than 50%, of salary.

On the January 16, 2008 adoption date of the plan, the Company s closing stock price was $40.71. On April 8, 2008, the Company achieved the interim target goal of $50 per share for 20 out of 60 consecutive trading days and a distribution totaling $3.1 million was paid to employees on April 17, 2008. On June 2, 2008, the Company achieved the final target goal of $60 per share for 20 out of 60 consecutive trading days and a distribution totaling $12.6 million was paid to employees on June 19, 2008. No further distributions will be made under this plan.

On July 24, 2008, the Company s Board of Directors adopted a second Supplemental Employee Incentive Plan (Plan II). Plan II is also intended to provide a compensation tool tied to stock market value creation to serve as an incentive and retention vehicle for full-time non-officer employees by providing for cash payments in the event the Company s common stock reaches a specified trading price.

Plan II provides for a final payout if, for any 20 trading days (which need not be consecutive) that fall within a period of 60 consecutive trading days ending on or before June 20, 2012, the closing price per share of the Company s common stock equals or exceeds the price goal of $105 per share. In such event, the 20th trading day on which such price condition is attained is the Final Trigger Date. The price goal is subject to adjustment by the Compensation Committee to reflect any stock splits, stock dividends or extraordinary cash distributions to stockholders. Under Plan II, each eligible employee may receive (upon approval by the Compensation Committee) a distribution of 50% of his or her base salary as of the Final Trigger Date (or 30% of base salary if the Company paid interim distributions upon the achievement of the interim price goal discussed below).

Plan II provides that a distribution of 20% of an eligible employee s base salary as of the Interim Trigger Date will be made (upon approval by the Compensation Committee) upon achieving the interim price goal of $85 per share on or before June 30, 2010. Interim distributions are determined as described above except that interim distributions will be based on 20%, rather than 50%, of salary. The Compensation Committee can increase the 50% or 20% payment as it applies to any employee.

Payments under either the interim or final distribution will occur as follows:

25% of the total distribution paid on the 15th business day following the interim or final trigger date, as applicable, and
75% of the total distribution paid based on the following deferred payment dates in the table below:

Period During which the Trigger Date Occurs	Deferred Payment Date
July 1, 2008 to June 30, 2009	The business day on or next following the 18 month anniversary of the applicable Trigger Date
July 1, 2009 to June 30, 2010	The business day on or next following the 12 month anniversary of the applicable Trigger Date
July 1, 2010 to December 31, 2010	The business day on or next following the 6 month anniversary of the applicable Trigger Date
January 1, 2011 to June 30, 2012	No deferral; entire payment is made on the 15th business day following the applicable Trigger Date

Any deferred portion will only be paid if the participant is employed by the Company, or has terminated employment by reason of retirement, death or disability (as provided in Plan II). Payments are subject to certain other restrictions contained in Plan II.

These awards under both plans discussed above have been accounted for as liability awards under SFAS No. 123(R), and the total expense for the first nine months of 2008 was $15.8 million. Of this total expense, $0.1 million was recorded in the third quarter of 2008.

12. CAPITAL STOCK

On June 20, 2008, the Company entered into an underwriting agreement, pursuant to which the Company sold an aggregate of 5,002,500 shares of common stock at a price to the Company of $62.66 per share. This aggregate share amount included 652,500 shares of common stock that were issued as a result of the exercise of the underwriters option to purchase additional shares. On June 25, 2008, the Company closed the public offering and received $313.5 million in net proceeds, after deducting underwriting discounts and commissions. These net proceeds were used temporarily to reduce outstanding borrowings under the Company s revolving credit facility prior to funding a portion of the purchase price of the Company s east Texas acquisition, which closed in the third quarter of 2008.

Immediately prior to (and in connection with) this issuance, the Company retired 5,002,500 shares of its treasury stock, which had a weighted-average purchase price of $16.46, representing $82.3 million. In accordance with the Company s policy, the excess of cost of the treasury stock over its par value was charged entirely to additional paid-in capital.

13. UNCERTAIN TAX POSITIONS

As of December 31, 2007, the unrecognized tax benefits were $2.4 million. During the quarter ended September 30, 2008, the Company executed a final settlement agreement with the Internal Revenue Service that reduced unrecognized tax benefits by $1.9 million. This reduction did not affect the effective tax rate. The amount of remaining unrecognized tax benefits as of September 30, 2008, if recognized, would not have a significant impact on the effective tax rate.

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, 2008, the related condensed consolidated statement of operations for the three-month and nine-month periods ended September 30, 2008 and 2007, and the condensed consolidated statement of cash flows for the nine-month periods ended September 30, 2008 and 2007. 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, 2007, 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, 2008, which included an explanatory paragraph related to the adoptions of FASB Interpretation No. 48, Accounting for Uncertainty in Income Taxes, an interpretation of FASB Statement No. 109, Statement of Financial Accounting Standards No. 158, Employers Accounting for Defined Benefit Pension and Other Postretirement Plans, an amendment of FASB Statements No. 87, 88, 106, and 132(R), and Statement of Financial Accounting Standards No. 123R, Share Based Payment (revised 2004), 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, 2007, 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 31, 2008

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, 2008 and 2007 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, 2007.

Overview

Operating revenues for the nine months ended September 30, 2008 increased by $175.0 million, or 33%, from the nine months ended September 30, 2007. Natural gas production revenues increased by $138.3 million, or 32%, for the nine months ended September 30, 2008 as compared to the nine months ended September 30, 2007 due to increases in all regions in both realized natural gas prices and natural gas production. Crude oil and condensate revenues increased by $15.8 million, or 40%, for the first nine months of 2008 as compared to the first nine months of 2007 due to an increase in realized crude oil prices in all regions, slightly offset by a decrease in crude oil production, primarily in the Gulf Coast and, to a lesser extent, in the West. Brokered natural gas revenues increased by $20.3 million due to an increase in sales price and, to a lesser extent, an increase in brokered volumes.

Our average realized natural gas price for the first nine months of 2008 was $8.64 per Mcf, 21% higher than the $7.15 per Mcf price realized in the same period of the prior year. Our average realized crude oil price for the first nine months of 2008 was $94.93 per Bbl, 53% higher than the $62.17 per Bbl price realized in the same period of the prior year. 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 the Results of Operations section. 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 accurately predict revenues.

On an equivalent basis, our production level for the first nine months of 2008 increased by nine percent from the first nine months of 2007. For the nine months ended September 30, 2008, we produced 69.6 Bcfe compared to production of 64.1 Bcfe for the comparable period of the prior year. Natural gas production was 66.1 Bcf and oil production was 580 Mbbls for the first nine months of 2008. Natural gas production increased by 10% when compared to the comparable period of the prior year, which had production of 60.3 Bcf. This increase was primarily a result of *(1)* increased natural gas production in the Gulf Coast region due to increased production in the Minden field, largely due to properties we acquired in east Texas in August 2008, and increased drilling in the County Line field, *(2)* increased production in the West region associated with an increase in the drilling program and *(3)* increased production in Canada due to increased drilling activity in the Hinton field. Production in the East region remained relatively flat period over period. Oil production decreased by 52 Mbbls, or eight percent, from 632 Mbbls in the first nine months of 2007 to 580 Mbbls produced in the first nine months of 2008. This was primarily the result of a decrease of 35 Mbbls in the Gulf Coast region as well as 17 Mbbls in the West region due to natural declines.

We had net income of $167.6 million, or $1.68 per share, for the nine months ended September 30, 2008 compared to net income of $125.4 million, or $1.29 per share, for the comparable period of the prior year. The increase in net income is primarily due to the increase in natural gas revenues (including brokered natural gas revenues) and, to a lesser extent, crude oil revenues, partially offset by higher operating expenses and an $11.9 million lower gain on sale of assets in 2008. Operating revenues increased by $175.0 million as discussed above. Operating expenses increased by $83.2 million in the first nine months of 2008 as compared to the first nine months of 2007, primarily due to increased depreciation, depletion and amortization (DD&A) expenses, increased general and administrative expenses resulting from higher stock compensation expense, and increased taxes other than income and brokered natural gas costs and, to a lesser extent, direct operations expenses. These impacts, along with an $11.2 million increase in interest and other expenses, increased income before taxes by $68.7 million and consequently increased income tax expense by $26.5 million.

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. In 2008, we expect to spend approximately $750 million in capital and exploration expenditures, excluding approximately $754 million associated with the east Texas acquisition described below and a significant lease acquisition program. The increased spending is primarily the result of additional planned drilling activity and related gathering and pipeline investments. We believe our cash on hand and operating cash flow in 2008 will be sufficient to fund a substantial portion of our budgeted capital and exploration spending. Any additional needs will be funded by borrowings from our credit facility. We may also reduce our budgeted capital and exploration spending to maintain sufficient liquidity. For the nine months ended September 30, 2008, approximately $1.2 billion has been invested in our exploration and development efforts.

During the first nine months of 2008, we drilled 333 gross wells (318 development, 12 exploratory and three extension wells) with a success rate of 99% compared to 359 gross wells (346 development, six exploratory and seven extension wells) with a success rate of 98% for the comparable period of the prior year. For the full year of 2008, we plan to drill approximately 450 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 manage our balance sheet in an effort to ensure that we have sufficient liquidity, and we intend to maintain spending discipline. We believe these strategies are appropriate for our portfolio of projects and the current industry environment and that this activity will continue to add shareholder value over the long term.

In August 2008, we completed the acquisition of producing properties, leasehold acreage and a natural gas gathering infrastructure in east Texas. We paid total net cash consideration of approximately $603.7 million (see Note 2 of the Notes to the Condensed Consolidated Financial Statements for further details). In order to finance the east Texas acquisition and repay outstanding borrowings under our revolving credit facility, we completed a public offering of our common stock in June 2008 and received net proceeds of $313.5 million (see Note 12 of the Notes to the Condensed Consolidated Financial Statements for further details). In July 2008, we closed a private placement of $425 million principal amount of senior unsecured fixed rate notes, which also funded a portion of the east Texas acquisition (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, 2008 were from funds generated from the sale of natural gas and crude oil production, the private placement of debt, the sale of common stock and, to a lesser extent, borrowings under our revolving credit facility. Cash flows provided by operating activities, borrowings and the sale of common stock were primarily used to fund our development (including acquisitions) and, to a lesser extent, exploratory expenditures, and to pay 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 Annual Report on Form 10-K for the year ended December 31, 2007 (Form 10-K), have also influenced prices throughout the recent years. Commodity prices have recently experienced increased volatility due to adverse market conditions in our 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 these variables discussed above. From time to time, our working capital will reflect a surplus, while at other times it will reflect a deficit. This fluctuation is not unusual. The recent financial and credit crisis has reduced credit availability and liquidity for some companies; however we believe we have adequate liquidity available to meet our working capital requirements.

	Nine Months Ended September 30,	
(In thousands)	**2008**	**2007**
Cash Flows Provided by Operating Activities	**$ 424,728**	$ 328,559
Cash Flows Used in Investing Activities	**(1,181,953)**	(432,380)
Cash Flows Provided by Financing Activities	**786,101**	76,418
Net Increase / (Decrease) in Cash and Cash Equivalents	**$ 28,876**	$ (27,403)

***Operating Activities*.** Net cash provided by operating activities in the first nine months of 2008 increased by $96.2 million over the comparable period in 2007. This increase is primarily due to the increase in net income as well as working capital changes. Key components impacting net operating cash flows are commodity prices, production volumes and operating costs. Average realized crude oil prices increased by 53% for the first nine months of 2008 versus the 2007 period and average realized natural gas prices increased by 21% over the same period. Equivalent production volumes increased by approximately nine percent in the first nine months of 2008 compared to the first nine months of 2007 as a result of higher natural gas production. We are unable to predict future commodity prices and, as a result, cannot provide any assurance about future levels of net cash provided by operating activities. We expect our realized natural gas and crude oil prices to be lower in the fourth quarter of 2008 due to recent price declines.

***Investing Activities*.** The primary uses of cash in investing activities were capital spending (including our recent acquisition of east Texas properties) and exploration expenses. We established the budget for these amounts based on our current estimate of future commodity prices. Due to the volatility of commodity prices and new opportunities which may arise, our capital expenditures may be periodically adjusted during any given year. Cash flows used in investing activities increased by $749.6 million from the first nine months of 2007 compared to the first nine months of 2008. The increase from 2007 to 2008 is due to an increase of $747.4 million in capital expenditures, including approximately $604.8 million related to increased acquisition activities. Additionally, there were $4.7 million of lower proceeds from the sale of assets, partially offset by reduced exploration expenditures of $2.5 million.

***Financing Activities*.** Cash flows provided by financing activities were $786.1 million for the first nine months of 2008, and included net proceeds from our private placement of debt and increased borrowings under our revolving credit facility, net proceeds from the sale of common stock issued in our public offering and proceeds from the exercise of stock options, and increased tax benefit for stock-based compensation, partially offset by dividend payments. Cash flows provided by financing activities were $76.4 million for the first nine months of 2007, and were comprised of a net increase in borrowings under our revolving credit facility, proceeds from the exercise of stock options and the tax benefit received from stock-based compensation, partially offset by dividend payments.

At September 30, 2008, we had $185 million of borrowings outstanding under our credit facility at a weighted-average interest rate of 4.4%. The credit facility provides for an available credit line of $350 million. 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 petroleum engineer) and other assets. The revolving term of the credit facility ends in December 2009 and is unsecured. We strive to manage our debt at a level below the available credit line in order to maintain excess borrowing capacity. Our revolving credit facility includes a covenant limiting our total debt. Management believes that we have the capacity to finance our spending plans and maintain our liquidity. At the same time, we will closely monitor the capital markets. As a result of market conditions and our increased level of borrowings, we may experience increased costs associated with future debt.

In June 2008, we entered into an underwriting agreement pursuant to which we sold an aggregate of 5,002,500 shares of common stock at a price to the Company of $62.66 per share. This aggregate share amount included 652,500 shares of common stock that were issued as a result of the exercise of the underwriters option to purchase additional shares. We received $313.5 million in net proceeds, after deducting underwriting discounts and commissions. These net proceeds were used temporarily to reduce outstanding borrowings under our revolving credit facility prior to funding a portion of the purchase price of our east Texas acquisition, which closed in the third quarter of 2008. Immediately prior to (and in connection with) this issuance, we retired 5,002,500 shares of treasury stock, which had a weighted-average purchase price of $16.46.

Our Board of Directors has authorized a share repurchase program under which we may purchase shares of our 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, 2008, we did not repurchase any shares of our 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, 2008 was 4,795,300. See Unregistered Sales of Equity Securities and Use of Proceeds Issuer Purchases of Equity Securities in Item 2 of Part II of this quarterly report.

Capitalization

Information about our capitalization is as follows:

(Dollars in millions)	**September 30, 2008**	December 31, 2007
Debt[1]	**$ 820.0**	$ 350.0
Stockholders Equity	**1,671.0**	1,070.3
Total Capitalization	**$ 2,491.0**	$ 1,420.3
Debt to Capitalization	**33%**	25%
Cash and Cash Equivalents	**$ 47.4**	$ 18.5

(1) Includes $20.0 million of current portion of long-term debt at both September 30, 2008 and December 31, 2007. Includes $185 million and $140 million of borrowings outstanding under our revolving credit facility at September 30, 2008 and December 31, 2007, respectively.

During the nine months ended September 30, 2008, we paid dividends of $9.0 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, 2008 and 2007:

(In millions)	**Nine Months Ended September 30, 2008**	**2007**
Capital Expenditures		
Drilling and Facilities	**$ 415.5**	$ 404.8
Leasehold Acquisitions	**106.0**	17.8
Acquisitions	**624.4**	0.6
Pipeline and Gathering	**25.4**	17.5
Other	**7.5**	16.8
	1,178.8	457.5
Exploration Expense	**18.8**	21.2
Total	**$ 1,197.6**	$ 478.7

For the full year of 2008, we plan to drill approximately 450 gross wells. This investment program includes approximately $750 million in total capital and exploration expenditures, up from $636.2 million in 2007. See the Overview discussion for additional information regarding the current year drilling program. We will continue to assess the natural gas and crude oil price environment and our liquidity position and may increase or decrease the capital and exploration expenditures accordingly.

Contractual Obligations

At September 30, 2008, we were obligated to make future payments under drilling rig commitments and firm gas transportation agreements as disclosed in our Annual Report on Form 10-K for the year ended December 31, 2007. 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.

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 Annual Report on Form 10-K for the year ended December 31, 2007, for further discussion of our critical accounting policies.

Statement of Financial Accounting Standards (SFAS) No. 159, The Fair Value Option for Financial Assets and Financial Liabilities, including an amendment of FASB Statement No. 115, became effective on January 1, 2008 and permits companies to choose, at specified dates, to measure certain eligible financial instruments at fair value. The provisions of SFAS No. 159 apply only to entities that elect to use the fair value option and to all entities with available-for-sale and trading securities. At the effective date, companies may elect the fair value option for eligible items that exist at that date, and the effect of the first remeasurement to fair value must be reported as a cumulative-effect adjustment to the opening balance of retained earnings. Since we did not elect to adopt the fair value option for eligible items, SFAS No. 159 has not had an impact on our financial position or results of operations.

Effective January 1, 2008, we adopted those provisions of SFAS No. 157, Fair Value Measurements, that were required to be adopted. This adoption did not have a material impact on any of our financial statements. Additional disclosures are required for transactions measured at fair value and we have included these disclosures in Note 7 of the Notes to the Condensed Consolidated Financial Statements.

In October 2008, the FASB issued FSP No. FAS 157-3, Estimating the Fair Value of a Financial Asset in a Market That Is Not Active to amend SFAS No.157 to provide guidance regarding how to determine the fair value of a financial asset when there is no active market for the asset at the measurement date. FSP No. FAS 157-3 clarifies how management s internal assumptions, such as internal cash flow and discount rate assumptions, should be considered in measuring fair value when observable data are not present. In addition, observable market information from an inactive market should be considered to determine fair value, and it is inappropriate to conclude that all market activity represents forced liquidations or distressed sales or to conclude that any transaction price can determine fair value. The use of broker quotes and pricing services should also be considered to assess the relevance of observable and unobservable data. When valuing financial assets, significant judgment is required. FSP No. FAS 157-3 is effective upon issuance and has been considered in conjunction with our third quarter 2008 financial reporting and results. There was no material impact on our financial position or results of operations for the nine months ended September 30, 2008.

As defined in SFAS No. 157, fair value is the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date (exit price). The transaction is based on a hypothetical transaction in the principal or most advantageous market considered from the perspective of the market participant that holds the asset or owes the liability.

We utilize 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. We attempt to utilize valuation techniques that maximize the use of observable inputs and minimize the use of unobservable inputs. We are able to classify fair value balances based on the observability of those inputs. SFAS No. 157 establishes a formal fair value hierarchy based on the inputs used to measure fair value. The hierarchy gives the highest priority to level 1 measurements and the lowest priority to level 3 measurements, and accordingly, level 1 measurements should be used whenever possible.

The three levels of the fair value hierarchy as defined by SFAS No. 157 are as follows:

Level 1: Valuations utilizing quoted, unadjusted prices for identical assets or liabilities in active markets that we have the ability to access. This is the most reliable evidence of fair value and does not require a significant degree of judgment. Examples include exchange-traded derivatives and listed equities that are actively traded.

Level 2: Valuations utilizing quoted prices in markets that are not considered to be active or financial instruments for which all significant inputs are observable, either directly or indirectly for substantially the full term of the asset or liability. Financial instruments that are valued using models or other valuation methodologies are included. Models used should primarily be industry-standard models that consider various assumptions and economic measures, such as interest rates, yield curves, time value, volatilities, contract terms, current market prices, credit risk or other market-corroborated inputs. Examples include most over-the-counter derivatives (non-exchange traded), physical commodities, most structured notes and municipal and corporate bonds.

Level 3: Valuations utilizing significant, unobservable inputs. This provides the least objective evidence of fair value and requires a significant degree of judgment. Inputs may be used with internally developed methodologies and should reflect an entity s assumptions using the best information available about the assumptions that market participants would use in pricing an asset or liability. Examples include certain corporate loans, real-estate and private equity investments and long-dated or complex over-the-counter derivatives.

Per SFAS No. 157, we have classified our assets and liabilities into these levels depending upon the data relied on to determine the fair values. The determination of fair value incorporates various factors required under SFAS No. 157. These factors include not only the credit standing of the counterparties involved in transactions with us resulting in receivables on our Condensed Consolidated Balance Sheet, but also the impact of our nonperformance risk on our liabilities.

The fair values of our natural gas and crude oil price collars and swaps are valued based upon quotes obtained from counterparties to the agreements and are designated as Level 3. The total Level 3 derivative liabilities were $3.0 million and total Level 3 derivative assets were $193.7 million at September 30, 2008. The derivative contracts were measured based on quotes from our 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. Although we utilize multiple quotes to assess the reasonableness of our values, we have not attempted to obtain sufficient corroborating market evidence to support classifying these derivative contracts as Level 2. We measured the nonperformance risk of our counterparties by reviewing credit default swap spreads for the various financial institutions in which we have derivative transactions. The resulting reduction to the net receivable derivative contract position was $9.4 million. In times where we have net derivative contract liabilities, our nonperformance risk is evaluated using a market credit spread provided by our bank.

Results of Operations

Third Quarters of 2008 and 2007 Compared

We reported net income in the third quarter of 2008 of $67.0 million, or $0.65 per share. For the corresponding quarter of 2007, we reported net income of $35.5 million, or $0.37 per share. Net income increased in the third quarter of 2008 by $31.5 million, primarily due to an increase in operating revenues partially offset by an increase in operating, interest and income tax expenses. Operating revenues increased by $73.9 million, largely due to increases in both natural gas production revenues and brokered natural gas revenues, and crude oil and condensate revenues. Operating expenses increased by $14.8 million between quarters largely due to increased DD&A, brokered natural gas costs, taxes other than income and, to a lesser extent, direct operations expense, partially offset by decreased general and administrative expenses resulting from lower stock compensation and by decreased exploration expenses. In addition, net income was impacted by an increase in expenses of $27.6 million resulting from a combination of higher income tax expense and interest and other expenses. Income tax expense was higher in the 2008 period as a result of increased income before income taxes in the third quarter of 2008 period compared to the third quarter of 2007 as well as an increase in the effective tax rate due to a West Virginia state tax ruling that had a favorable impact on our 2007 state tax liability.

Natural Gas Production Revenues

Our average total company realized natural gas production sales price, including the realized impact of derivative instruments, was $8.66 per Mcf for the three months ended September 30, 2008 compared to $6.80 per Mcf for the comparable period of the prior year. These prices include the realized impact of derivative instrument settlements, which decreased the price by $0.30 per Mcf in 2008 and increased the price by $1.40 per Mcf in 2007. The following table excludes the unrealized gain from the change in derivative fair value of $1.3 million, which has been included within Natural Gas Production Revenues in the Condensed Consolidated Statement of Operations for the quarter ended September 30, 2008. There was no revenue impact from the unrealized change in natural gas derivative fair value for the three months ended September 30, 2007.

	Three Months Ended September 30, 2008	Three Months Ended September 30, 2007	Variance Amount	Variance Percent
Natural Gas Production *(Mmcf)*				
East	**6,349**	6,276	73	1%
Gulf Coast	**9,278**	6,790	2,488	37%
West	**6,569**	6,580	(11)	0%
Canada	**780**	990	(210)	(21%)
Total Company	**22,976**	20,636	2,340	11%
Natural Gas Production Sales Price *($/Mcf)*				
East	**$ 8.44**	$ 7.37	$ 1.07	15%
Gulf Coast	**$ 9.82**	$ 7.82	$ 2.00	26%
West	**$ 7.37**	$ 5.47	$ 1.90	35%
Canada	**$ 7.60**	$ 4.95	$ 2.65	54%
Total Company	**$ 8.66**	$ 6.80	$ 1.86	27%
Natural Gas Production Revenue *(In thousands)*				
East	**$ 53,558**	$ 46,267	$ 7,291	16%
Gulf Coast	**91,092**	53,101	37,991	72%
West	**48,441**	36,027	12,414	34%
Canada	**5,928**	4,905	1,023	21%
Total Company	**$ 199,019**	$ 140,300	$ 58,719	42%
Price Variance Impact on Natural Gas Production Revenue *(In thousands)*				
East	**$ 6,750**			
Gulf Coast	**18,534**			
West	**12,473**			
Canada	**2,066**			
Total Company	**$ 39,823**			
Volume Variance Impact on Natural Gas Production Revenue *(In thousands)*				
East	**$ 541**			
Gulf Coast	**19,457**			
West	**(59)**			
Canada	**(1,043)**			
Total Company	**$ 18,896**			

The increase in Natural Gas Production Revenue of $58.7 million is due to the increase in realized natural gas sales prices in addition to an increase in overall natural gas production. Natural gas production in the Gulf Coast region increased due to increased production in the Minden field, largely as a result of the properties we acquired in east Texas in August 2008, as well as increased drilling in the County Line field. This increase was partially offset by a decrease in natural gas production in Canada due to increased royalty burden and natural decline.

Brokered Natural Gas Revenue and Cost

	Three Months Ended September 30, 2008	Three Months Ended September 30, 2007	Variance Amount	Variance Percent
Sales Price *($/Mcf)*	**$ 11.77**	$ 7.14	$ 4.63	65%
Volume Brokered *(Mmcf)*	**x 2,027**	x 2,126	(99)	(5%)
Brokered Natural Gas Revenues *(In thousands)*	**$ 23,855**	$ 15,179		
Purchase Price *($/Mcf)*	**$ 10.31**	$ 6.22	$ 4.09	66%
Volume Brokered *(Mmcf)*	**x 2,027**	x 2,126	(99)	(5%)
Brokered Natural Gas Cost *(In thousands)*	**$ 20,891**	$ 13,223		
Brokered Natural Gas Margin *(In thousands)*	**$ 2,964**	$ 1,956	$ 1,008	52%

(In thousands)	
Sales Price Variance Impact on Revenue	**$ 9,385**
Volume Variance Impact on Revenue	**(709)**
	$ 8,676

(In thousands)	
Purchase Price Variance Impact on Purchases	**$ (8,284)**
Volume Variance Impact on Purchases	**616**
	$ (7,668)

The increased brokered natural gas margin of $1.0 million is a result of an increase in sales price that outpaced the increase in purchase price, partially offset by a decrease in the volumes brokered in the third quarter of 2008 over the same period in the prior year.

Crude Oil and Condensate Revenues

Our average total company realized crude oil sales price, including the realized impact of derivative instruments, was $99.34 per Bbl for the third quarter of 2008 compared to $70.85 per Bbl for the third quarter of 2007. These prices include the realized impact of derivative instrument settlements, which decreased the price by $15.39 per Bbl in 2008. There was no realized impact of derivative instrument settlements in the third quarter of 2007. There was no revenue impact from the unrealized change in crude oil and condensate derivative fair value for the three months ended September 30, 2008 or 2007.

	Three Months Ended September 30,		Variance	
	2008	**2007**	**Amount**	**Percent**
Crude Oil Production *(Mbbl)*				
East	**5**	7	(2)	(29%)
Gulf Coast	**147**	153	(6)	(4%)
West	**43**	49	(6)	(12%)
Canada	**6**	4	2	50%
Total Company	**201**	213	(12)	(6%)
Crude Oil Sales Price *($/Bbl)*				
East	**$ 106.23**	$ 68.12	$ 38.11	56%
Gulf Coast	**$ 95.28**	$ 71.16	$ 24.12	34%
West	**$ 112.24**	$ 70.85	$ 41.39	58%
Canada	**$ 100.46**	$ 63.47	$ 36.99	58%
Total Company	**$ 99.34**	$ 70.85	$ 28.49	40%
Crude Oil Revenue *(In thousands)*				
East	**$ 580**	$ 494	$ 86	17%
Gulf Coast	**13,977**	10,903	3,074	28%
West	**4,795**	3,439	1,356	39%
Canada	**650**	248	402	162%
Total Company	**$ 20,002**	$ 15,084	$ 4,918	33%
Price Variance Impact on Crude Oil Revenue *(In thousands)*				
East	**$ 209**			
Gulf Coast	**3,539**			
West	**1,767**			
Canada	**303**			
Total Company	**$ 5,818**			
Volume Variance Impact on Crude Oil Revenue *(In thousands)*				
East	**$ (123)**			
Gulf Coast	**(465)**			
West	**(411)**			
Canada	**99**			
Total Company	**$ (900)**			

The increase in realized crude oil prices, partially offset by a decrease in production, resulted in a net revenue increase of $4.9 million. The decrease in oil production is mainly the result of a natural decline in crude oil production in the Gulf Coast and West regions.

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,			
	2008		2007	
(In thousands)	**Realized**	**Unrealized**	**Realized**	**Unrealized**
Operating Revenues Increase / (Decrease) to Revenue				
Cash Flow Hedges				
Natural Gas Production	**$ (6,964)**	**$ 1,260**	$ 28,882	$
Crude Oil	**(3,093)**			
Total Cash Flow Hedges	**$ (10,057)**	**$ 1,260**	$ 28,882	$

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 derivative contract counterparties are JPMorgan Chase, Morgan Stanley, Goldman Sachs, BNP Paribas and Bank of Montreal.

Operating Expenses

Total costs and expenses from operations increased by $14.8 million in the third quarter of 2008 compared to the same period of 2007. The primary reasons for this fluctuation are as follows:

Depreciation, Depletion and Amortization increased by $11.2 million in the third quarter of 2008 compared with the third quarter of 2007. This is primarily due to the impact on the DD&A rate of higher capital costs and commencement of production from the east Texas acquisition.

General and Administrative expenses decreased by $10.0 million in the third quarter of 2008 compared with the third quarter of 2007. This is primarily due to decreased stock compensation expense related to the 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 performance share awards in which we are ranked against our peers.

Brokered Natural Gas Cost increased by $7.7 million from the third quarter of 2007 to the third quarter of 2008. See the preceding table titled Brokered Natural Gas Revenue and Cost for further analysis.

Taxes Other Than Income increased by $6.2 million from the third quarter of 2007 to the third quarter of 2008 primarily due to higher production taxes as a result of higher operating revenues, partially offset by lower ad valorem and franchise taxes.

Impairment of Oil and Gas Properties decreased by $4.6 million from the third quarter of 2007 to the third quarter of 2008 as a result of an impairment recorded in 2007 in the Gulf Coast region resulting from two non-commercial development completions in a small field in north Louisiana. No impairment of oil and gas properties was recorded in 2008. Further analysis of this impairment in 2007 is discussed in Note 2 of the Notes to the Consolidated Financial Statements.

Direct Operations expenses increased by $4.0 million from the third quarter of 2007 to the third quarter of 2008 primarily due to higher personnel and labor expenses as well as increased workover, treating, compressor and maintenance costs.

Impairment of Unproved Properties increased by $2.6 million from the third quarter of 2007 to the third quarter of 2008, primarily due to increased lease acquisition costs in several exploratory areas.

Interest Expense, Net

Interest expense, net increased by $6.5 million in the third quarter of 2008 primarily due to increased interest expense related to the debt we issued in our July 2008 private placement and, to a lesser extent, higher average credit facility borrowings, offset in part by a lower weighted-average interest rate on our revolving credit facility borrowings, lower outstanding borrowings on our 7.19% fixed rate debt and increased interest income from short-term investments. Weighted-average borrowings under our credit facility based on daily balances were approximately $116 million during the third quarter of 2008 compared to approximately $57 million during the third quarter of 2007. The weighted-average effective interest rate on the credit facility decreased to 4.7% in the third quarter of 2008 from 8.0% in the third quarter of 2007.

Income Tax Expense

Income tax expense increased by $21.1 million due to a comparable increase in our pre-tax income. The effective tax rate for the third quarter of 2008 and 2007 was 35.7% and 31.3%, respectively. The increase in the effective tax rate is primarily due to a West Virginia state tax ruling that had a favorable impact on our 2007 state tax liability.

Nine Months of 2008 and 2007 Compared

We reported net income in the first nine months of 2008 of $167.6 million, or $1.68 per share. For the corresponding period of 2007, we reported net income of $125.4 million, or $1.29 per share. Net income increased in the first nine months of 2008 by $42.2 million, primarily due to an increase in operating revenues, partially offset by increased operating, interest and income tax expenses and a decrease in gain on sale of assets. Operating revenues increased by $175.0 million, largely due to increases in both natural gas production revenues and brokered natural gas revenues and crude oil and condensate revenues. Operating expenses increased by $83.2 million between periods largely due to higher DD&A, general and administrative expenses resulting from higher stock compensation, brokered natural gas costs, taxes other than income and, to a lesser extent, direct operations expense, partially offset by lower impairments of oil and gas properties and exploration expenses. In addition, net income was impacted by a decrease in gain on sale of assets of $11.9 million as well as an increase in expenses of $37.7 million resulting from a combination of increased income tax expense and interest and other expenses. Income tax expense was higher in the 2008 period as a result of higher income before income taxes in the first nine months of 2008 compared to the first nine months of 2007, in addition to an increase in the effective tax rate due to an increase in our overall state tax rate for 2008.

Natural Gas Production Revenues

Our average total company realized natural gas production sales price, including the realized impact of derivative instruments, was $8.64 per Mcf for the nine months ended September 30, 2008 compared to $7.15 per Mcf for the comparable period of the prior year. These prices include the realized impact of derivative instrument settlements, which decreased the price by $0.42 per Mcf in 2008 and increased the price by $0.99 per Mcf in 2007. The following table excludes the unrealized loss from the change in derivative fair value of $1.6 million, which has been included within Natural Gas Production Revenue in the Condensed Consolidated Statement of Operations for the nine months ended September 30, 2008. There was no revenue impact from the unrealized change in natural gas derivative fair value for the nine months ended September 30, 2007.

	Nine Months Ended September 30,		Variance	
	2008	**2007**	**Amount**	**Percent**
Natural Gas Production *(Mmcf)*				
East	**18,284**	18,199	85	0%
Gulf Coast	**24,394**	19,724	4,670	24%
West	**20,050**	19,402	648	3%
Canada	**3,369**	2,992	377	13%
Total Company	**66,097**	60,317	5,780	10%
Natural Gas Production Sales Price *($/Mcf)*				
East	**$ 8.78**	$ 7.76	$ 1.02	13%
Gulf Coast	**$ 9.53**	$ 7.95	$ 1.58	20%
West	**$ 7.58**	$ 6.00	$ 1.58	26%
Canada	**$ 7.84**	$ 5.63	$ 2.21	39%
Total Company	**$ 8.64**	$ 7.15	$ 1.49	21%
Natural Gas Production Revenue *(In thousands)*				
East	**$ 160,479**	$ 141,253	$ 19,226	14%
Gulf Coast	**232,403**	156,745	75,658	48%
West	**151,883**	116,330	35,553	31%
Canada	**26,411**	16,850	9,561	57%
Total Company	**$ 571,176**	$ 431,178	$ 139,998	32%
Price Variance Impact on Natural Gas Production Revenue *(In thousands)*				
East	**$ 18,563**			
Gulf Coast	**38,547**			
West	**31,670**			
Canada	**7,438**			
Total Company	**$ 96,218**			
Volume Variance Impact on Natural Gas Production Revenue *(In thousands)*				
East	**$ 663**			
Gulf Coast	**37,111**			
West	**3,883**			
Canada	**2,123**			
Total Company	**$ 43,780**			

The increase in Natural Gas Production Revenue of $140.0 million is due to the increase in realized natural gas sales prices in addition to an increase in natural gas production. Natural gas production in the Gulf Coast region increased due to increased production in the Minden field, largely due to the properties we acquired in east Texas in August 2008, as well as increased drilling in the County Line field. In addition, natural gas production increased in the West region associated with an increase in the drilling program and increased in Canada due to increased drilling in the Hinton field.

Brokered Natural Gas Revenue and Cost

	Nine Months Ended September 30, 2008	Nine Months Ended September 30, 2007	Variance Amount	Variance Percent
Sales Price *($/Mcf)*	**$ 10.81**	$ 8.40	$ 2.41	29%
Volume Brokered *(Mmcf)*	**x 8,017**	x 7,903	114	1%
Brokered Natural Gas Revenues *(In thousands)*	**$ 86,663**	$ 66,357		
Purchase Price *($/Mcf)*	**$ 9.40**	$ 7.34	$ 2.06	28%
Volume Brokered *(Mmcf)*	**x 8,017**	x 7,903	114	1%
Brokered Natural Gas Cost *(In thousands)*	**$ 75,321**	$ 57,973		
Brokered Natural Gas Margin *(In thousands)*	**$ 11,342**	$ 8,384	$ 2,958	35%

(In thousands)	
Sales Price Variance Impact on Revenue	**$ 19,348**
Volume Variance Impact on Revenue	**958**
	$ 20,306

(In thousands)	
Purchase Price Variance Impact on Purchases	**$ (16,511)**
Volume Variance Impact on Purchases	**(837)**
	$ (17,348)

The increased brokered natural gas margin of $3.0 million is a result of an increase in sales price that outpaced the increase in purchase price as well as an increase in the volumes brokered in the first nine months of 2008 over the same period in the prior year.

Crude Oil and Condensate Revenues

Our average total company realized crude oil sales price, including the realized impact of derivative instruments, was $94.93 per Bbl for the first nine months of 2008 compared to $62.17 per Bbl for the first nine months of 2007. These prices include the realized impact of derivative instrument settlements, which decreased the price by $15.05 per Bbl in 2008 and increased the price by $0.29 per Bbl in 2007. There was no revenue impact from the unrealized change in crude oil and condensate derivative fair value for the nine months ended September 30, 2008 or 2007.

	Nine Months Ended September 30,		Variance	
	2008	**2007**	**Amount**	**Percent**
Crude Oil Production *(Mbbl)*				
East	**17**	20	(3)	(15%)
Gulf Coast	**427**	462	(35)	(8%)
West	**119**	136	(17)	(13%)
Canada	**17**	14	3	21%
Total Company	**580**	632	(52)	(8%)
Crude Oil Sales Price *($/Bbl)*				
East	**$ 104.63**	$ 60.78	$ 43.85	72%
Gulf Coast	**$ 90.58**	$ 62.27	$ 28.31	45%
West	**$ 109.60**	$ 62.81	$ 46.79	75%
Canada	**$ 92.03**	$ 54.97	$ 37.06	67%
Total Company	**$ 94.93**	$ 62.17	$ 32.76	53%
Crude Oil Revenue *(In thousands)*				
East	**$ 1,807**	$ 1,215	$ 592	49%
Gulf Coast	**38,634**	28,760	9,874	34%
West	**12,999**	8,527	4,472	52%
Canada	**1,649**	787	862	110%
Total Company	**$ 55,089**	$ 39,289	$ 15,800	40%
Price Variance Impact on Crude Oil Revenue *(In thousands)*				
East	**$ 758**			
Gulf Coast	**12,074**			
West	**5,550**			
Canada	**689**			
Total Company	**$ 19,071**			
Volume Variance Impact on Crude Oil Revenue *(In thousands)*				
East	**$ (166)**			
Gulf Coast	**(2,200)**			
West	**(1,078)**			
Canada	**173**			
Total Company	**$ (3,271)**			

The increase in realized crude oil prices, partially offset by a decrease in production, resulted in a net revenue increase of $15.8 million. The decrease in oil production is mainly the result of a natural decline in crude oil production in the Gulf Coast and West regions.

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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,			
	2008		2007	
(In thousands)	**Realized**	**Unrealized**	**Realized**	**Unrealized**
Operating Revenues - Increase / (Decrease) to Revenue				
Cash Flow Hedges				
Natural Gas Production	**$ (27,766)**	**$ (1,649)**	$ 59,601	$
Crude Oil	**(8,731)**		182	
Total Cash Flow Hedges	**$ (36,497)**	**$ (1,649)**	$ 59,783	$

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 derivative contract counterparties are JPMorgan Chase, Morgan Stanley, Goldman Sachs, BNP Paribas and Bank of Montreal.

Operating Expenses

Total costs and expenses from operations increased by $83.2 million in the first nine months of 2008 compared to the same period of 2007. The primary reasons for this fluctuation are as follows:

Depreciation, Depletion and Amortization increased by $27.5 million in the first nine months of 2008 compared with the first nine months of 2008. This is primarily due to the impact on the DD&A rate of higher capital costs and higher natural gas production volumes, including the east Texas acquisition.

General and Administrative expenses increased by $19.8 million in the first nine months of 2008 compared with the first nine months of 2007. This is primarily due to increased stock compensation expense related to the payouts of our supplemental employee incentive plan bonuses as well as increased expense related to our performance shares.

Brokered Natural Gas Cost increased by $17.3 million from the first nine months of 2007 compared to the first nine months of 2008. See the preceding table titled Brokered Natural Gas Revenue and Cost for further analysis.

Taxes Other Than Income increased by $14.6 million from the nine months ended September 30, 2007 compared to the nine months ended September 30, 2008 due to higher production taxes as a result of higher operating revenues and, to a lesser extent, higher ad valorem taxes, partially offset by lower franchise taxes.

Direct Operations expenses increased by $8.0 million from the first nine months of 2007 compared to the first nine months of 2008 primarily due to higher personnel and labor expenses, treating costs, compressor costs, vehicle and fuel expenses and maintenance expenses.

Impairment of Oil and Gas Properties decreased by $4.6 million from the first nine months of 2007 compared to the first nine months of 2008 as a result of an impairment recorded in 2007 in the Gulf Coast region resulting from two non-commercial development completions in a small field in north Louisiana. No impairment of oil and gas properties was recorded in 2008. Further analysis of this impairment in 2007 is discussed in Note 2 of the Notes to the Consolidated Financial Statements.

Impairment of Unproved Properties increased by $3.0 million from the first nine months of 2007 compared to the first nine months of 2008, primarily due to increased lease acquisition costs in several exploratory areas.

Interest Expense, Net

Interest expense, net increased by $11.2 million in the first nine months of 2008 primarily due to increased interest expense related to the debt we issued in our July 2008 private placement and, to a lesser extent, higher average credit facility borrowings and lower interest income from our short-term investments, offset in part by a lower weighted-average interest rate on our revolving credit facility borrowings and lower outstanding borrowings on our 7.19% fixed rate debt. Weighted-average borrowings under our credit facility based on daily balances were approximately $159 million during the first nine months of 2008 compared to approximately $21 million during the first nine months of 2007. The weighted-average effective interest rate on the credit facility decreased to 5.1% in the first nine months of 2008 from 8.1% in the first nine months of 2007.

Income Tax Expense

Income tax expense increased by $26.5 million due to a comparable increase in our pre-tax income. The effective tax rate for the first nine months of 2008 and 2007 was 36.1% and 35.2%, respectively. The increase in the effective tax rate is primarily due to an increase in our overall state tax rate for 2008.

Recently Issued Accounting Pronouncements

In June 2008, the Financial Accounting Standards Board (FASB) issued FASB Staff Position (FSP) No. Emerging Issues Task Force (EITF) 03-6-1, Determining Whether Instruments Granted in Share-Based Payment Transactions Are Participating Securities. Under this FSP, unvested share-based payment awards that contain nonforfeitable rights to dividends or dividend equivalents, whether they are paid or unpaid, are considered participating securities and should be included in the computation of earnings per share pursuant to the two-class method. FSP No. EITF 03-6-1 is 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 should be adjusted retrospectively and early application is not permitted. We do not believe that FSP No. EITF 03-6-1 will have a material impact on our financial position, results of operations or cash flows.

In May 2008, the FASB issued SFAS No. 162, The Hierarchy of Generally Accepted Accounting Principles, which identifies a consistent framework for selecting accounting principles to be used in preparing financial statements for nongovernmental entities that are presented in conformity with United States generally accepted accounting principles (GAAP). The current GAAP hierarchy was criticized due to its complexity, ranking position of FASB Statements of Financial Accounting Concepts and the fact that it is directed at auditors rather than entities. SFAS No. 162 will be effective 60 days following the SEC s approval of the Public Company Accounting Oversight Board amendments to AU Section 411, The Meaning of Present Fairly in Conformity with Generally Accepted Accounting Principles. The FASB does not expect that SFAS No. 162 will have a change in current practice, and we do not believe that SFAS No. 162 will have an impact on our financial position, results of operations or cash flows.

In March 2008, the FASB issued SFAS No. 161, Disclosures about Derivative Instruments and Hedging Activities, which amends SFAS No. 133, Accounting for Derivative Instruments and Hedging Activities. Enhanced disclosures to improve financial reporting transparency are required and include disclosure about the location and amounts of derivative instruments in the financial statements, how derivative instruments are accounted for and how derivatives affect an entity s financial position, financial performance and cash flows. 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. SFAS No. 161 is effective for financial statements issued for fiscal years and interim periods beginning after November 15, 2008, with early application and comparative disclosures encouraged, but not required. We have not yet adopted SFAS No. 161. We do not believe that SFAS No. 161 will have an impact on its financial position, results of operations or cash flows.

In December 2007, the FASB issued SFAS No. 160, Noncontrolling Interest in Consolidated Financial Statements, an amendment of Accounting Research Bulletin (ARB) No. 51. SFAS No. 160 clarifies that a noncontrolling interest (previously commonly referred to as a minority interest) in a subsidiary is an ownership interest in the consolidated entity and should be reported as equity in the consolidated financial statements. The presentation of the consolidated income statement has been changed by SFAS No. 160, and consolidated net income attributable to both the parent and the noncontrolling interest is now required to be reported separately. Previously, net income attributable to the noncontrolling interest was typically reported as an expense or other deduction in arriving at consolidated net income and was often combined with other financial statement amounts. In addition, the ownership interests in subsidiaries held by parties other than the parent must be clearly identified, labeled, and presented in equity in the consolidated financial statements separately from the parent s equity. Subsequent changes in a parent s ownership interest while the parent retains its controlling financial interest in its subsidiary should be accounted for consistently, and when a subsidiary is deconsolidated, any retained noncontrolling equity interest in the former subsidiary must be initially measured at fair value. Expanded disclosures, including a reconciliation of equity balances of the parent and noncontrolling interest, are also required. SFAS No. 160 is effective for fiscal years, and interim periods within those fiscal years, beginning on or after December 15, 2008 and earlier adoption is prohibited. Prospective application is required. At this time, we do not have any material noncontrolling interests in consolidated subsidiaries. Therefore, we do not believe that the adoption of SFAS No. 160 will have a material impact on our financial position, results of operations or cash flows.

In December 2007, the FASB issued SFAS No. 141(R), Business Combinations. SFAS No. 141(R) was issued in an effort to continue the movement toward the greater use of fair values in financial reporting and increased transparency through expanded disclosures. It changes how business acquisitions are accounted for and will impact financial statements at the acquisition date and in subsequent periods. Certain of these changes will introduce more volatility into earnings. The acquirer must now record all assets and liabilities of the acquired business at fair value, and related transaction and restructuring costs will be expensed rather than the previous method of being capitalized as part of the acquisition. SFAS No. 141(R) also impacts the annual goodwill impairment test associated with acquisitions, including those that close before the effective date of SFAS No. 141(R). The definitions of a business and a business combination have been expanded, resulting in more transactions qualifying as business combinations. SFAS No. 141(R) is effective for fiscal years, and interim periods within those fiscal years, beginning on or after December 31, 2008 and earlier adoption is prohibited. We cannot predict the impact that the adoption of SFAS No. 141(R) will have on our financial position, results of operations or cash flows with respect to any acquisitions completed after December 31, 2008.

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.

Hedges on Production Swaps

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 2008, natural gas price swaps covered 6,143 Mmcf, or nine percent, of our first nine months of 2008 gas production at an average price of $9.70 per Mcf. During the first nine months of 2008, we entered into natural gas price swaps covering a portion of our anticipated 2008, 2009 and 2010 production, including production related to the east Texas acquisition.

At September 30, 2008, we had open natural gas price swap contracts covering a portion of our anticipated 2008, 2009 and 2010 production as follows:

Contract Period	Volume in Mmcf	Natural Gas Price Swaps Weighted-Average Contract Price *(per Mcf)*	Net Unrealized Gain *(In thousands)*
As of September 30, 2008			
Fourth Quarter 2008	3,678	$ 11.22	
Three Months Ended December 31, 2008	**3,678**	**$ 11.22**	**$ 14,578**
First Quarter 2009	3,964	$ 12.18	
Second Quarter 2009	4,009	12.18	
Third Quarter 2009	4,053	12.18	
Fourth Quarter 2009	4,053	12.18	
Year Ended December 31, 2009	**16,079**	**$ 12.18**	**$ 52,542**
First Quarter 2010	4,758	$ 11.43	
Second Quarter 2010	4,811	11.43	
Third Quarter 2010	4,863	11.43	
Fourth Quarter 2010	4,863	11.43	
Year Ended December 31, 2010	**19,295**	**$ 11.43**	**$ 38,296**

We had one crude oil price swap covering 46 Mbbl, or eight percent, of our first nine months of 2008 production at a price of $127.15 per Bbl. During the first nine months of 2008, we entered into crude oil price swaps covering a portion of our anticipated 2008, 2009 and 2010 production. At September 30, 2008, we had open crude oil price swap contracts covering a portion of our anticipated 2008, 2009 and 2010 production as follows:

Contract Period	Volume in Mbbl	Crude Oil Price Swaps Contract Price *(per Bbl)*	Net Unrealized Gain *(In thousands)*
As of September 30, 2008			
Fourth Quarter 2008	46	$ 127.15	
Three Months Ended December 31, 2008	**46**	**$ 127.15**	**$ 1,567**
First Quarter 2009	90	$ 125.25	
Second Quarter 2009	91	125.25	
Third Quarter 2009	92	125.25	
Fourth Quarter 2009	92	125.25	
Year Ended December 31, 2009	**365**	**$ 125.25**	**$ 8,070**
First Quarter 2010	90	$ 125.00	
Second Quarter 2010	91	125.00	
Third Quarter 2010	92	125.00	
Fourth Quarter 2010	92	125.00	
Year Ended December 31, 2010	**365**	**$ 125.00**	**$ 6,934**

Hedges on Production Options

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 2008, natural gas price collars covered 39,399 Mmcf, or 60%, of our first nine months of 2008 gas production, with a weighted-average floor of $8.51 per Mcf and a weighted-average ceiling of $10.65 per Mcf.

At September 30, 2008, we had open natural gas price collar contracts covering a portion of our anticipated 2008 and 2009 production as follows:

	Natural Gas Price Collars		
Contract Period	**Volume in Mmcf**	**Weighted-Average Ceiling / Floor** *(per Mcf)*	**Net Unrealized Gain** *(In thousands)*
As of September 30, 2008			
Fourth Quarter 2008	14,775	$ 10.83 / $8.59	
Three Months Ended December 31, 2008	**14,775**	**$ 10.83 / $8.59**	**$ 18,572**
First Quarter 2009	11,652	$ 12.39 / $9.40	
Second Quarter 2009	11,781	12.39 / 9.40	
Third Quarter 2009	11,910	12.39 / 9.40	
Fourth Quarter 2009	11,910	12.39 / 9.40	
Year Ended December 31, 2009	**47,253**	**$ 12.39 / $9.40**	**$ 62,282**

During the first nine months of 2008, a crude oil price collar covered 274 Mbbls, or 47%, of our first nine months of 2008 crude oil production, with a floor of $60.00 per Bbl and a ceiling of $80.00 per Bbl.

At September 30, 2008 we had one open crude oil price collar contract covering a portion of our anticipated 2008 production as follows:

	Crude Oil Price Collar		
Contract Period	**Volume in Mbbl**	**Ceiling / Floor** *(per Bbl)*	**Net Unrealized Loss** *(In thousands)*
As of September 30, 2008			
Fourth Quarter 2008	92	$ 80.00 / $60.00	
Three Months Ended December 31, 2008	**92**	**$ 80.00 / $60.00**	**$ (2,682)**

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 amounts set forth under the net unrealized gain / (loss) columns in the tables above represent our total unrealized gain / (loss) position at September 30, 2008. Also impacting the total unrealized net gain (reflecting the net receivable position) in accumulated other comprehensive income / (loss) in Condensed Consolidated Balance Sheet is a reduction of $9.4 million related to our assessment of our counterparties nonperformance risk. This risk was evaluated by reviewing credit default swap spreads for the various financial institutions in which we have derivative transactions.

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.

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 2008 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, 2007 and Item 1A of Part II of the Company s Quarterly Report on Form 10-Q for the quarter ended June 30, 2008.

The global financial crisis may have impacts on our business and financial condition that we currently cannot predict.

The continued credit crisis and related turmoil in the global financial system may have an impact on our business and our financial condition, and we may face challenges if conditions in the financial markets do not improve. Our ability to access the capital markets may be restricted at a time when we would like, or need, to raise financing, which could have an impact on our flexibility to react to changing economic and business conditions. The economic situation could have an impact on our lenders or customers, causing them to fail to meet their obligations to us. Additionally, market conditions could have an impact on our commodity hedging arrangements if our counterparties are unable to perform their obligations or seek bankruptcy protection. Additionally, the current economic situation could lead to reduced demand for oil and natural gas, or lower prices for oil and natural gas, or both, which could have a negative impact on our revenues.

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, 2008, 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, 2008 was 4,795,300.

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

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 31, 2008

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

Chief Executive Officer

(Principal Executive Officer)

October 31, 2008

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

(Principal Financial Officer)

October 31, 2008

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

(Principal Accounting Officer)