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, 2006

¨ **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, or a non-accelerated filer. See definition of accelerated filer and large accelerated filer in Rule 12b-2 of the Exchange Act. (Check one): Large accelerated filer x Accelerated filer ¨ Non-accelerated filer ¨

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 24, 2006, there were 47,914,159 shares of Common Stock, Par Value $.10 Per Share, outstanding.

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PART I. FINANCIAL INFORMATION

ITEM 1. Financial Statements

CABOT OIL & GAS CORPORATION

CONDENSED CONSOLIDATED STATEMENT OF OPERATIONS (Unaudited)

(In thousands, except per share amounts)	Three Months Ended September 30, 2006	Three Months Ended September 30, 2005	Nine Months Ended September 30, 2006	Nine Months Ended September 30, 2005
OPERATING REVENUES				
Natural Gas Production	**$ 140,261**	$ 121,477	**$ 436,931**	$ 337,566
Brokered Natural Gas	**17,075**	18,756	**67,389**	60,768
Crude Oil and Condensate	**26,435**	21,336	**80,283**	57,250
Other	**973**	188	**5,703**	2,131
	184,744	161,757	**590,306**	457,715
OPERATING EXPENSES				
Brokered Natural Gas Cost	**15,282**	16,550	**59,924**	53,549
Direct Operations - Field and Pipeline	**19,893**	14,246	**55,478**	43,171
Exploration	**13,561**	16,665	**39,972**	47,396
Depreciation, Depletion and Amortization	**32,088**	26,578	**96,815**	79,346
Impairment of Unproved Properties	**3,826**	4,092	**11,289**	11,146
General and Administrative	**10,715**	9,679	**38,079**	27,339
Taxes Other Than Income	**14,366**	14,939	**44,439**	37,053
	109,731	102,749	**345,996**	299,000
Gain on Sale of Assets	**229,733**	15	**229,944**	74
INCOME FROM OPERATIONS	**304,746**	59,023	**474,254**	158,789
Interest Expense and Other	**6,978**	5,339	**19,151**	15,461
Income Before Income Taxes and Cumulative Effect of Accounting Change	**297,768**	53,684	**455,103**	143,328
Income Tax Expense	**108,748**	19,928	**165,651**	53,388
INCOME BEFORE CUMULATIVE EFFECT OF ACCOUNTING CHANGE	**189,020**	33,756	**289,452**	89,940
CUMULATIVE EFFECT OF ACCOUNTING CHANGE, NET OF TAX (Note 11)			**(403)**	
NET INCOME	**$ 189,020**	$ 33,756	**$ 289,049**	$ 89,940
Basic Earnings Per Share - Before Accounting Change	**$ 3.92**	$ 0.69	**$ 5.96**	$ 1.84
Diluted Earnings Per Share - Before Accounting Change	**$ 3.84**	$ 0.68	**$ 5.85**	$ 1.81
Basic Loss Per Share - Accounting Change	**$**	$	**$ (0.01)**	$
Diluted Loss Per Share - Accounting Change	**$**	$	**$ (0.01)**	$
Basic Earnings Per Share	**$ 3.92**	$ 0.69	**$ 5.95**	$ 1.84
Diluted Earnings Per Share	**$ 3.84**	$ 0.68	**$ 5.84**	$ 1.81
Weighted Average Common Shares Outstanding	**48,230**	48,951	**48,548**	48,865
Diluted Common Shares (Note 5)	**49,162**	49,665	**49,508**	49,613

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

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CABOT OIL & GAS CORPORATION

CONDENSED CONSOLIDATED BALANCE SHEET (Unaudited)

(In thousands, except share amounts)	September 30, 2006	December 31, 2005
ASSETS		
Current Assets		
Cash and Cash Equivalents	$ 322,123	$ 10,626
Accounts Receivable	104,157	168,248
Inventories	41,120	24,616
Deferred Income Taxes	8,333	15,674
Derivative Contracts	58,415	1,736
Other	12,859	9,412
Total Current Assets	547,007	230,312
Properties and Equipment, Net (Successful Efforts Method)	1,390,182	1,238,055
Deferred Income Taxes	25,190	19,587
Derivative Contracts	9,725	164
Other Assets	7,856	7,252
	$ 1,979,960	$ 1,495,370
LIABILITIES AND STOCKHOLDERS EQUITY		
Current Liabilities		
Accounts Payable	$ 137,333	$ 140,006
Current Portion of Long-Term Debt	20,000	20,000
Deferred Income Taxes	22,968	941
Derivative Contracts	16	22,478
Income Taxes Payable	89,887	41
Accrued Liabilities	35,339	35,118
Total Current Liabilities	305,543	218,584
Long-Term Debt	380,000	320,000
Deferred Income Taxes	330,855	289,381
Other Liabilities	53,778	67,194
Commitments and Contingencies (Note 6)		
Stockholders Equity		
Common Stock:		
Authorized 120,000,000 and 80,000,000 Shares of $.10 Par Value in 2006 and 2005, respectively		
Issued 50,510,809 Shares and 50,081,983 Shares in 2006 and 2005, respectively	5,051	5,008
Additional Paid-in Capital	414,201	397,349
Retained Earnings	535,383	252,167
Accumulated Other Comprehensive Income / (Loss)	40,839	(15,115)
Less Treasury Stock, at Cost:		
2,602,350 and 1,513,850 Shares in 2006 and 2005, respectively	(85,690)	(39,198)
Total Stockholders Equity	909,784	600,211
	$ 1,979,960	$ 1,495,370

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

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CABOT OIL & GAS CORPORATION

CONDENSED CONSOLIDATED STATEMENT OF CASH FLOWS (Unaudited)

(In thousands)	Nine Months Ended September 30, 2006	2005
CASH FLOWS FROM OPERATING ACTIVITIES		
Net Income	**$ 289,049**	$ 89,940
Adjustments to Reconcile Net Income to Cash Provided by Operating Activities:		
Cumulative Effect of Accounting Change	**403**	
Depreciation, Depletion and Amortization	**96,815**	79,346
Impairment of Unproved Properties	**11,289**	11,146
Deferred Income Tax Expense	**31,514**	18,225
Gain on Sale of Assets	**(229,944)**	(74)
Exploration Expense	**39,972**	47,396
Unrealized Loss on Derivatives		2,051
Stock-Based Compensation Expense and Other	**11,859**	7,154
Changes in Assets and Liabilities:		
Accounts Receivable	**64,090**	(6,086)
Inventories	**(16,504)**	(11,424)
Other Current Assets	**(3,447)**	1,167
Other Assets	**(438)**	(203)
Accounts Payable and Accrued Liabilities	**(34,137)**	1,516
Income Taxes Payable	**95,278**	3,292
Other Liabilities	**6,007**	3,665
Stock-Based Compensation Tax Benefit	**(5,756)**	
Net Cash Provided by Operating Activities	**356,050**	247,111
CASH FLOWS FROM INVESTING ACTIVITIES		
Capital Expenditures	**(344,620)**	(241,504)
Proceeds from Sale of Assets	**322,987**	996
Exploration Expense	**(39,972)**	(47,396)
Net Cash Used in Investing Activities	**(61,605)**	(287,904)
CASH FLOWS FROM FINANCING ACTIVITIES		
Increase in Debt	**195,000**	85,000
Decrease in Debt	**(135,000)**	(75,000)
Increase in Book Overdrafts		25,691
Sale of Common Stock Proceeds	**3,620**	4,088
Stock-Based Compensation Tax Benefit	**5,756**	
Purchase of Treasury Stock	**(46,492)**	(571)
Dividends Paid	**(5,832)**	(5,254)
Net Cash Provided by Financing Activities	**17,052**	33,954
Net Increase / (Decrease) in Cash and Cash Equivalents	**311,497**	(6,839)
Cash and Cash Equivalents, Beginning of Period	**10,626**	10,026
Cash and Cash Equivalents, End of Period	**$ 322,123**	$ 3,187

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

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CABOT OIL & GAS CORPORATION

NOTES TO THE CONDENSED CONSOLIDATED FINANCIAL STATEMENTS (Unaudited)

1. FINANCIAL STATEMENT PRESENTATION

During interim periods, Cabot Oil & Gas Corporation (the Company) follows the same accounting policies used in its Annual Report to Stockholders and its Annual Report on Form 10-K for the year ended December 31, 2005 filed with the Securities and Exchange Commission (SEC). People using financial information produced for interim periods are encouraged to refer to the footnotes in the Annual Report on Form 10-K for the year ended December 31, 2005 when reviewing interim financial results. 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 presentation. The results of operations for any interim period are not necessarily indicative of the results of operations for the entire year.

Our independent registered public accounting firm has performed a review of these condensed consolidated interim financial statements in accordance with standards established by the Public Company Accounting Oversight Board (United States). Pursuant to Rule 436(c) under the Securities Act of 1933, this report should not be considered a part of a registration statement prepared or certified by PricewaterhouseCoopers LLP within the meanings of Sections 7 and 11 of the Act.

Effective January 1, 2006, the Company adopted the provisions of Statement of Financial Accounting Standards (SFAS) No. 123(R), Share Based Payment (revised 2004), which replaces the provisions of Accounting Principles Board Opinion (APB) No. 25, Accounting for Stock Issued to Employees and SFAS No. 123, Accounting for Stock-Based Compensation, (as amended). The Company elected the modified prospective transition method for adoption, and accordingly, no adjustments to prior period financial statements have been made. Upon adoption, the Company recorded a cumulative effect of change in accounting principle totaling $0.4 million, net of tax, in the Condensed Consolidated Statement of Operations for the first quarter of 2006. Adoption of SFAS No. 123(R) increased income from operations and income before income taxes by approximately $1.2 million and increased net income by approximately $0.7 million for the nine months ended September 30, 2006. There was no material impact on the Condensed Consolidated Statement of Cash Flows. See Note 11 of the Notes to the Condensed Consolidated Financial Statements for additional disclosure.

Recently Issued Accounting Pronouncements

In February 2006, the Financial Accounting Standards Board (FASB) issued SFAS No. 155, Accounting for Certain Hybrid Financial Instruments-an amendment of FASB Statements No. 133 and 140. SFAS No. 155 amends SFAS No. 133, Accounting for Derivative Instruments and Hedging Activities and SFAS No. 140, Accounting for Transfers and Servicing of Financial Assets and Extinguishments of Liabilities, and also resolves issues addressed in SFAS No. 133 Implementation Issue No. D1, Application of Statement 133 to Beneficial Interests in Securitized Financial Assets. SFAS No. 155 was issued to eliminate the exemption from applying SFAS No. 133 to interests in securitized financial assets so that similar instruments are accounted for in a similar fashion, regardless of the instrument s form. The Company does not believe that its financial position, results of operations or cash flows will be impacted by SFAS No. 155 as the Company does not currently hold any hybrid financial instruments.

In July 2006, the FASB issued FASB Interpretation (FIN) No. 48, Accounting for Uncertainty in Income Taxes-an interpretation of FASB Statement No. 109. This Interpretation provides guidance for recognizing and measuring uncertain tax positions, as defined in SFAS No. 109, Accounting for Income Taxes. FIN No. 48 prescribes a two-step process for accounting for income tax uncertainties. First, a threshold condition of more likely than not should be met to determine whether any of the benefit of the uncertain tax position should be recognized in the financial statements. If the recognition threshold is met, FIN 48 provides additional guidance on measuring the amount of the uncertain tax position. Guidance is also provided regarding derecognition, classification, interest and penalties, interim period accounting, transition and disclosure of these uncertain tax positions. FIN 48 is effective for fiscal years beginning after December 15, 2006. The Company is currently evaluating the impact, if any, that this Interpretation may have on its financial position, results of operations and cash flows.

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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 U.S. generally accepted accounting principles (GAAP) 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. No new fair value measurements are prescribed, and SFAS No. 157 is intended to codify the several definitions of fair value included in various accounting standards. However, the application of this Statement may change current practices for certain companies. SFAS No. 157 is effective for fiscal years beginning after November 15, 2007. The Company is currently evaluating what impact SFAS No. 157 may have on its financial position, results of operations or cash flows.

In September 2006, the FASB issued SFAS No. 158, Employers Accounting for Defined Benefit Pension and Other Postretirement Plans, an amendment of FASB Statements No. 87, 88, 106, and 132(R). SFAS No. 158 requires recognition of the funded status of a benefit plan in the Company s balance sheet and the recognition through other comprehensive income of gains, losses, prior service costs and credits, net of tax, arising during the period but not included as a component of periodic benefit cost. In addition, the measurement date of plan assets and obligations must be the Company s balance sheet date. Additional disclosures in the notes to the financial statements will also be required and guidance is prescribed regarding the selection of discount rates to be used in measuring the benefit obligation. For public companies, the effective date of SFAS No. 158 is as of the end of the fiscal year ending after December 15, 2006. The effective date of the new measurement date provision is for fiscal years ending after December 15, 2008; however, the Company s measurement date is currently its balance sheet date, so no change will be required. The Company plans to adopt this standard using the prospective transition method of adoption effective with its Annual Report on Form 10-K for the year ended December 31, 2006. The anticipated incremental effect of SFAS No. 158 is to increase the Company s total liabilities and total assets by $18.7 million and $7.1 million, respectively, and to decrease total stockholders equity by $11.6 million based on actuarial reports as of September 30, 2006.

In September 2006, the SEC Staff issued Staff Accounting Bulletin (SAB) No. 108, Considering the Effects of Prior Year Misstatements when Quantifying Misstatements in Current Year Financial Statements, in an effort to address diversity in the accounting practice of quantifying misstatements and the potential for improper amounts on the balance sheet. Prior to the issuance of SAB No. 108, the two methods used for quantifying the effects of financial statement errors were the roll-over and iron curtain methods. Under the roll-over method, the primary focus is the income statement, including the reversing effect of prior year misstatements. The criticism of this method is that misstatements can accumulate on the balance sheet. On the other hand, the iron curtain method focuses on the effect of correcting the ending balance sheet, with less importance on the reversing effects of prior year errors in the income statement. SAB No. 108 establishes a dual approach which requires the quantification of the effect of financial statement errors on each financial statement, as well as related disclosures. Public companies are required to record the cumulative effect of initially adopting the dual approach method in the first year ending after November 16, 2006 by recording any necessary corrections to asset and liability balances with an offsetting adjustment to the opening balance of retained earnings. The use of this cumulative effect transition method also requires detailed disclosures of the nature and amount of each error being corrected and how and when they arose. The Company is currently evaluating the impact that SAB No. 108 may have on its financial position, results of operations and cash flows.

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2. PROPERTIES AND EQUIPMENT

Properties and equipment are comprised of the following:

(In thousands)	September 30, 2006	December 31, 2005
Unproved Oil and Gas Properties	**$ 107,619**	$ 107,787
Proved Oil and Gas Properties	**1,996,857**	1,970,407
Gathering and Pipeline Systems	**192,841**	178,876
Land, Building and Improvements	**4,897**	4,892
Other	**32,991**	33,077
	2,335,205	2,295,039
Accumulated Depreciation, Depletion and Amortization	**(945,023)**	(1,056,984)
	$ 1,390,182	$ 1,238,055

At both September 30, 2006 and December 31, 2005, the Company did not have any capitalized well costs that have been capitalized for greater than one year after drilling was suspended.

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Disposition of Assets

On September 29, 2006, the Company completed the sale of its offshore portfolio and certain south Louisiana properties to Phoenix Exploration Company LP (Phoenix) for a gross sales price of $340.0 million. The properties sold included proved reserves of approximately 98 Bcfe as of the August 1, 2006 effective date, including 68 Bcfe of proved reserved recorded as of December 31, 2005, and had average daily production for the nine months ended September 30, 2006 of 47.4 Mmcfe.

Pursuant to the Asset Purchase Agreement (the Agreement) dated August 25, 2006, the gross sales price is to be offset by the net cash flow (as defined in the Agreement) from operation of the properties from August 1, 2006 and other purchase price adjustments, if any. The net proceeds from the sale are expected to be used to add funding to the Company s capital program, repurchase shares of common stock, repay outstanding debt under the revolving credit facility and pay taxes related to the transaction. Also pursuant to the Agreement, the Company entered into certain commodity price swaps on behalf of Phoenix. At closing on September 29, 2006, these derivative instruments were assigned to Phoenix, and the Company was released from all rights and obligations with respect thereto. There was no ultimate impact on the Company s financial statements due to the existence of these swaps.

Through September 30, 2006, the Company had received approximately $321.4 million in net proceeds from this sale of its offshore and south Louisiana properties. Net proceeds of $321.4 million reflects the $340.0 million gross sales price, reduced by purchase price adjustments of $3.1 million as well as consents and preferential rights expected to be settled in the fourth quarter of 2006 of $15.5 million. A net gain of $229.7 million ($143.6 million, net of tax) is recorded in the Statement of Operations for the third quarter of 2006, calculated as follows:

(in millions)	
Cash Proceeds	$ 321.4
Less:	
Remaining purchase price adjustments	12.8
Carrying value of properties sold	102.2
Asset retirement obligation of properties sold	(23.8)
Transaction costs	0.5
Pre-tax gain	$ 229.7

The estimate of required purchase price adjustments shown in the preceding table and recorded in the Company s September 30, 2006 balance sheet are expected to be settled in the fourth quarter of 2006. The net impact of the purchase price adjustments will be reflected in cash flows from investing activities when such settlements are made. In addition, a gain of approximately $12.0 million is expected to be recognized in the fourth quarter of 2006, in connection with the closing of certain property sales to Phoenix for which third party consents had not been obtained as of September 30, 2006 and sales to other parties that executed their contractual preferential rights.

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3. ADDITIONAL BALANCE SHEET INFORMATION

Certain balance sheet amounts are comprised of the following:

(In thousands)	September 30, 2006	December 31, 2005
Accounts Receivable		
Trade Accounts	**$ 93,423**	$ 147,016
Joint Interest Accounts	**15,731**	14,319
Current Income Tax Receivable		12,239
Other Accounts	**376**	315
	109,530	173,889
Allowance for Doubtful Accounts	**(5,373)**	(5,641)
	$ 104,157	$ 168,248
Inventories		
Natural Gas and Oil in Storage	**$ 32,204**	$ 18,279
Tubular Goods and Well Equipment	**7,736**	7,161
Pipeline Imbalances	**1,180**	(824)
	$ 41,120	$ 24,616
Other Current Assets		
Drilling Advances	**$ 3,268**	$ 2,169
Prepaid Balances	**9,253**	6,939
Other Accounts	**338**	304
	$ 12,859	$ 9,412
Accounts Payable		
Trade Accounts	**$ 17,585**	$ 18,227
Natural Gas Purchases	**9,433**	12,208
Royalty and Other Owners	**44,874**	49,312
Capital Costs	**52,599**	37,489
Taxes Other Than Income	**4,868**	10,329
Drilling Advances	**2,000**	5,760
Wellhead Gas Imbalances	**2,251**	2,175
Other Accounts	**3,723**	4,506
	$ 137,333	$ 140,006
Accrued Liabilities		
Employee Benefits	**$ 8,918**	$ 9,020
Taxes Other Than Income	**19,398**	16,188
Interest Payable	**5,300**	6,818
Other Accounts	**1,723**	3,092
	$ 35,339	$ 35,118
Other Liabilities		
Postretirement Benefits Other Than Pension	**$ 8,704**	$ 6,517

Accrued Pension Cost		**6,917**		5,904
Rabbi Trust Deferred Compensation Plan		**5,660**		4,883
Accrued Plugging and Abandonment Liability		**21,952**		42,991
Other Accounts		**10,545**		6,899
	$	**53,778**	$	67,194

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4. LONG-TERM DEBT

At September 30, 2006, the Company had $150 million of debt outstanding under its revolving credit facility. Subsequent to the end of the third quarter, on October 2, 2006, the Company repaid the entire $150 million outstanding balance. The credit facility provides for an available credit line of $250 million, which can be expanded up to $350 million, either with the existing banks or new banks. 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 the $150 million of debt outstanding under the credit facility, the Company had the following debt outstanding at September 30, 2006:

- $80 million of 12-year 7.19% Notes due in November 2009, which consisted of $60 million of long-term debt and $20 million of current portion of long-term debt, to be repaid in four 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

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

5. EARNINGS PER SHARE

Basic Earnings per 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 using the treasury stock method except that the denominator is increased 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 months and nine months ended September 30, 2006 and 2005.

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2006	**2005**	**2006**	**2005**
Shares - basic	**48,229,689**	48,951,439	**48,548,489**	48,865,202
Dilution effect of stock options and awards at end of period	**932,260**	713,848	**959,631**	747,805
Shares - diluted	**49,161,949**	49,665,287	**49,508,120**	49,613,007

Stock awards and shares excluded from diluted earnings per share due to the anti-dilutive effect

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 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 have requested class certification and allege that the Company failed to pay royalty based upon the wholesale market value of the gas, that it 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.

Discovery and pleadings necessary to place the class certification issue before the state court have been ongoing. The Court entered an order on June 1, 2005 granting the motion for class certification. The parties have negotiated a modification to the order which will result in the dismissal of the claims related to the gas sales contract settlement in connection with the Columbia Gas Transmission bankruptcy proceedings and that will limit the claims to those arising on and after December 17, 1991. The Court has postponed the trial date from April 17, 2006, in light of the case involving an unrelated party pending before the West Virginia Supreme Court of Appeals described below. The Company intends to challenge the class certification order by filing a Petition for Writ of Prohibition with the West Virginia Supreme Court of Appeals.

The West Virginia Supreme Court of Appeals issued its decision in a case involving an unrelated party on June 15, 2006, which became final on July 15, 2006. The decision may negatively impact some of the defenses raised on behalf of the Company in its litigation with respect to the issue of deductibility of post-production expenses under certain leases, but the Company believes that in a significant number of leases it has lease language, factual distinctions and defenses that are not implicated by the ruling. At a status conference held on October 24, 2006, the case against the Company was re-activated to the docket and trial was set for August 13, 2007. The Company continues to investigate how this recent ruling may impact its defense of the case.

The Company is vigorously defending the case. A reserve has been established that management believes is adequate based on its estimate of the probable outcome of this case.

Texas Title Litigation

On January 6, 2003, the Company was served with Plaintiffs Second Amended Original Petition in Romeo Longoria, et al. v. Exxon Mobil Corporation, et al. in the 79th Judicial District Court of Brooks County, Texas. Plaintiffs filed their Second Supplemental Original Petition on November 12, 2004 and their Third Supplemental Original Petition on February 22, 2005 (which added Wynn-Crosby 1996, Ltd. and Dominion Oklahoma Texas Exploration & Production, Inc.). Plaintiffs filed their Third Amended Original Petition on February 21, 2006, which incorporated all prior supplemental petitions. Plaintiffs allege that they are the owners of a one-half undivided mineral interest in and to certain lands in Brooks County, Texas. Cody Energy, LLC, a subsidiary of the Company, acquired certain leases and wells in 1997 and 1998.

The plaintiffs allege that they are entitled to be declared the rightful owners of an undivided interest in minerals and all improvements on the lands on which the Company acquired these leases. The plaintiffs also assert claims for trespass to try title, action to remove a cloud on the title, failure to properly account for royalty, fraud, trespass and conversion, all for unspecified actual and exemplary damages. Plaintiffs claim that they acquired title to the property by adverse possession. Plaintiffs also assert the discovery rule and a claim of fraudulent concealment to avoid the affirmative defense of limitations. In August 2005, the case was abated until late February 2006, during which time the parties were allowed to amend pleadings or add additional parties to the litigation. Plaintiffs did not join additional parties by the abatement deadline. Defendants, including the Company, re-urged its motion to dismiss, and on April 5, 2006, the Court granted the motion, dismissing the oil company defendants, without prejudice. Because all defendants were not dismissed at that time, the order dismissing the Company was not then final. A motion to finalize the proceedings in the trial court via severance of the dismissed defendants was filed April 25, 2006, and the remaining defendants moved to join the motions that led to the dismissal of the Company. At a hearing on June 23, 2006, the Court dismissed the remaining defendants, and effectively denied the plaintiffs attempt to modify the prior dismissal order, which is now final.

Plaintiffs filed a Notice of Appeal on July 17, 2006. Although the record is not yet complete and, therefore, specific appellate deadlines have not been set, the Company expects that, following briefing and oral argument, the appellate court will issue its decision by the end of 2007 or early 2008.

Raymondville Area

In April 2004, the Company s wholly owned subsidiary, Cody Energy, LLC, filed suit in state court in Willacy County, Texas against certain of its co-working interest owners in the Raymondville Area, located in Kenedy and Willacy Counties. In early 2003, Cody had proposed a new prospect under the terms of the Joint Operating Agreement. Some of the co-working interest owners elected not to participate. The initial well was successful and subsequent wells have been drilled to exploit the discovery made in the first well.

The working interest owners who elected not to participate notified Cody that they believed that they had the right to participate in wells drilled after the initial well. Cody contends that the working interest owners that elected not to participate are required to assign their interest in the prospect to those who elected to participate. The defendants filed a counter claim against Cody, and one of the defendants filed a lien against Cody s interest in the leases in the Raymondville area.

Cody has signed a settlement agreement with certain of the defendants representing approximately 3% of the interest in the area. Cody and the remaining defendant filed cross motions for summary judgment. In August 2005, the trial judge entered an order granting Cody s Motion for Summary Judgment requiring the remaining defendant to assign to Cody all of its interest in the prospect and to remove the lien filed against Cody s interest. The defendant filed a Motion for Reconsideration and Opposition to Proposed Order. The Court, on March 24, 2006, denied the Motion.

On July 12, 2006, Cody entered into a Purchase and Sale Agreement to acquire all of the defendant s interest in the Raymondville Field. The agreement would make the summary judgment ruling by the trial judge a final order, dismiss, with prejudice, all pending counter claims filed by such defendant and remove the lien against Cody s properties filed by such defendant. Cody completed the acquisition in the third quarter of 2006. The lien has been removed and the parties filed a joint motion to make the summary judgment a final order and dismiss all other claims. The order making the summary judgment final and dismissing all of the defendant s claims was signed by the judge on September 7, 2006.

Commitment and Contingency Reserves

The Company has established 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 $8.8 million of additional loss with respect to those matters in which reserves have been established. Future changes in the facts and circumstances could result in the actual liability exceeding the estimated ranges of loss and amounts accrued.

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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 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 entered into firm gas transportation agreements that provide firm transportation capacity rights on pipeline systems in Canada, the West and the East regions. The remaining terms on these agreements range from less than one year to 21 years and require the Company to pay transportation demand charges regardless of the amount of pipeline capacity utilized by the Company. The amount of demand charges on firm gas transportation agreements has decreased by approximately $3.8 million over the total length of these contracts from the amount previously disclosed in the Company s Annual Report on Form 10-K for the year ended December 31, 2005. This is due to rate changes and released volumes on certain contracts, partially offset by increased charges as a result of new contracts entered into in Canada. As of September 30, 2006, demand charges for 2006 are expected to be $7.1 million, a decrease of $4.6 million from the $11.7 million figure previously disclosed.

Future obligations under firm gas transportation agreements in effect at September 30, 2006 are as follows:

(In thousands)	
2007	$ 9,516
2008	7,744
2009	6,553
2010	3,629
2011	3,381
Thereafter	52,123
	$ 82,946

Rig Commitments

During the second quarter of 2006, the Company entered into a long-term contract for the use of an additional land drilling rig in the Gulf Coast with an existing contracted rig provider. The Company is obligated to pay $8.0 million over the one year contract starting on the delivery date in September 2006. Additionally, commitments on two rigs with existing contracted rig providers disclosed in the Annual Report on Form 10-K for the year ended December 31, 2005 have been renewed for an additional $1.8 million expected to be paid in 2008.

In its Annual Report on Form 10-K for the year ended December 31, 2005, the Company also disclosed that it had commitments on four rigs under contract that were not yet delivered. During October 2006, two of these rigs were delivered and it is expected that a third will be delivered by October 31, 2006. The daily rates on two of these rigs have increased in accordance with the contracts as a result of increased contractor expenses. The Company expects to pay an additional $1.5 million over approximately the next three years.

Guarantees

On June 28, 2006, the Company announced the commencement of an offering under its Mineral, Royalty and Overriding Royalty Interest Plan. The Company assisted certain non-executive employees in obtaining loans to purchase an interest in the offering by providing a guarantee of repayment should the non-executive employee fail to repay the loan. The repayment term for all of these loans is five years. The outstanding loan balances and fair value of these guarantees are immaterial to the Company s financial statements. All loans are collateralized by the interests transferred to the employees in the producing properties.

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7. 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. Under the Company s revolving credit agreement, the aggregate level of commodity hedging must not exceed 100% of the anticipated future equivalent production during the period covered by these cash flow hedges. At September 30, 2006, the Company had 26 cash flow hedges open: 24 natural gas price collar arrangements and two crude oil collar arrangements. At September 30, 2006, a $68.1 million ($42.2 million net of tax) unrealized gain was recorded in Accumulated Other Comprehensive Income, along with a $58.4 million short-term derivative receivable and a $9.7 million long-term derivative receivable. The change in the fair value of derivatives designated as hedges that is effective is initially recorded to Accumulated Other Comprehensive Income. The ineffective portion, if any, of the change in the fair value of derivatives designated as hedges, and the change in fair value of all other derivatives, is recorded currently in earnings as a component of Natural Gas Production and Crude Oil and Condensate Revenue, as appropriate.

Assuming no change in commodity prices, after September 30, 2006 the Company would expect to reclassify to the Statement of Operations, over the next 12 months, $36.2 million in after-tax income associated with commodity hedges. This reclassification represents the net short-term receivable associated with open positions currently not reflected in earnings at September 30, 2006 related to anticipated 2006 and 2007 production.

During the first nine months of 2006, the Company entered into one new oil collar contract and 16 new natural gas collar contracts covering a portion of its 2007 production. As of September 30, 2006, natural gas price collars for 2007 cover 34,246 Mmcf of production at a weighted average floor of $9.09 and a weighted average ceiling of $12.45. The oil price collar for 2007 covers 365 Mbbl of production at a floor of $60.00 and a ceiling of $80.00.

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8. COMPREHENSIVE INCOME

Comprehensive Income includes Net Income and certain items recorded directly to Stockholders Equity and classified as Accumulated Other Comprehensive Income. The following table illustrates the calculation of Comprehensive Income for the three and nine month periods ended September 30, 2006 and 2005.

	Three Months Ended September 30,				**Nine Months Ended September 30,**			
(In thousands)	**2006**		**2005**		**2006**		**2005**	
Accumulated Other Comprehensive Income / (Loss) - Beginning of Period		**$ 15,330**		$ (21,074)		**$ (15,115)**		$ (20,351)
Net Income	**$ 189,020**		33,756		**$ 289,049**		$ 89,940	
Other Comprehensive Income / (Loss)								
Reclassification Adjustment for Settled Contracts, net of taxes of $3,242, ($9,085), $6,523 and ($15,720), respectively	**(5,290)**		14,735		**(10,643)**		25,495	
Changes in Fair Value of Hedge Positions, net of taxes of ($18,913), $41,034, ($40,292) and $48,578, respectively	**30,859**		(66,080)		**65,740**		(78,621)	
Minimum Pension Liability, net of taxes of $ -, $ -, $ - and ($794), respectively							1,287	
Foreign Currency Translation Adjustment, net of taxes of $38, ($679), ($525) and ($538), respectively	**(60)**		1,101		**857**		872	
Total Other Comprehensive Income / (Loss)	**25,509**	**25,509**	(50,244)	(50,244)	**55,954**	**55,954**	(50,967)	(50,967)
Comprehensive Income / (Loss)	**$ 214,529**		$ (16,488)		**$ 345,003**		$ 38,973	
Accumulated Other Comprehensive Income / (Loss) - End of Period		**$ 40,839**		$ (71,318)		**$ 40,839**		$ (71,318)

Changes in the components of accumulated other comprehensive income, net of taxes, for the nine months ended September 30, 2006 are as follows:

Accumulated Other Comprehensive Income

(in thousands)	**Net Gains / (Losses) on Cash Flow Hedges**	**Minimum Pension Liability**	**Foreign Currency Translation Adjustment**	**Total**
Balance at December 31, 2005	$ (12,860)	$ (3,170)	$ 915	$ (15,115)
Net change in unrealized gains on cash flow hedges, net of taxes of $33,769	55,097			55,097
Change in foreign currency translation adjustment, net of taxes of $525			857	857
Balance at September 30, 2006	**$ 42,237**	**$ (3,170)**	**$ 1,772**	**$ 40,839**

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9. ASSET RETIREMENT OBLIGATIONS

The following table reflects the changes in the asset retirement obligations during the nine months ended September 30, 2006.

(In thousands)	
Carrying amount of asset retirement obligations at December 31, 2005	$ 42,991
Liabilities added during the current period	1,727
Liabilities settled and divested during the current period	(23,875)
Current period accretion expense	1,109
Carrying amount of asset retirement obligations at September 30, 2006	**$ 21,952**

Accretion expense is $1.1 million for both the nine months ended September 30, 2006 and 2005 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, 2006 and 2005 are as follows:

	For the Three Months Ended September 30,		For the Nine Months Ended September 30,	
(In thousands)	**2006**	**2005**	**2006**	**2005**
Qualified and Non-Qualified Pension Plans				
Current Period Service Cost	**$ 680**	$ 558	**$ 2,040**	$ 1,674
Interest Cost	**583**	495	**1,749**	1,485
Expected Return on Plan Assets	**(521)**	(355)	**(1,473)**	(1,065)
Amortization of Prior Service Cost	**44**	44	**132**	132
Amortization of Net Loss	**303**	225	**909**	675
Net Periodic Benefit Cost	**$ 1,089**	$ 967	**$ 3,357**	$ 2,901
Postretirement Benefits Other than Pension Plans				
Current Period Service Cost	**$ 197**	$ 169	**$ 591**	$ 507
Interest Cost	**219**	151	**658**	453
Plan Termination (Gain) / Loss	**(21)**	80	**(64)**	240
Recognized Net Actuarial Loss / (Gain)	**8**	(20)	**24**	(60)
Amortization of Prior Service Cost	**238**	227	**714**	681
Amortization of Net Obligation at Transition	**158**	162	**474**	486
Total Postretirement Benefit Cost	**$ 799**	$ 769	**$ 2,397**	$ 2,307

Employer Contributions

The funding levels of the pension and postretirement plans are in compliance with standards set by applicable law or regulation. The Company previously disclosed in its financial statements for the year ended December 31, 2005 that it expected to contribute less than $0.1 million to its non-qualified pension plan and approximately $0.6 million to the postretirement benefit plan during 2006. It is anticipated that these contributions will be made prior to December 31, 2006. The Company does not have any required minimum funding obligations for its qualified pension plan in 2006. The Company made a $2.0 million contribution to the qualified pension plan during the second quarter of 2006. Management has not determined if any additional discretionary funding will be made to the qualified pension plan during the remainder of 2006.

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11. STOCK-BASED COMPENSATION

Incentive Plans

Under the Company s 2004 Incentive Plan, incentive and non-statutory stock options, 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 addition to the automatic award of an option to purchase 15,000 shares of common stock on the date the non-employee directors first join the board of directors. A total of 2,550,000 shares of common stock may be issued under the 2004 Incentive Plan. Under the 2004 Incentive Plan, no more than 900,000 shares may be used for stock awards that are not subject to the achievement of performance based goals, and no more than 1,500,000 shares may be issued pursuant to incentive stock options.

Adoption of SFAS No. 123(R)

Prior to January 1, 2006, the Company accounted for stock-based compensation in accordance with the intrinsic value based method prescribed by APB No. 25. Under the intrinsic value based method, no compensation expense was recorded for stock options granted when the exercise price for options granted was equal to or greater than the fair value of the Company s common stock on the date of the grant.

Beginning January 1, 2006, the Company began accounting for stock-based compensation under SFAS No. 123(R), which applies to new awards and to awards modified, repurchased or cancelled after December 31, 2005. The Company records compensation expense based on the fair value of awards as described below. Additionally, compensation expense for the portion of the awards for which the requisite service period has not been rendered that are outstanding at December 31, 2005 is recognized as the requisite service is rendered on or after January 1, 2006.

Compensation expense that has been charged against income for stock-based awards in the third quarter of 2006 and 2005 is $3.2 million and $4.3 million, pre-tax, respectively, and is included in General and Administrative Expense in the Condensed Consolidated Statement of Operations. For the first nine months of 2006 and 2005, stock-based compensation expense is $11.8 million and $6.8 million, respectively. In the first nine months of 2006, compensation expense includes amortization of restricted stock grants, stock options, SARs and performance shares at fair value. Compensation expense in the first nine months of 2005 only includes amortization of restricted stock grants and compensation expense related to performance shares.

Prior to the adoption of SFAS No. 123(R), the Company presented tax benefits resulting from tax deductions related to stock-based compensation as an operating cash flow. Under SFAS No. 123(R), the tax benefits resulting from tax deductions in excess of expense is reported as an operating cash outflow and a financing cash inflow. For the first nine months of 2006, $5.8 million is reported in these two separate line items in the Condensed Consolidated Statement of Cash Flows.

The cumulative effect of adoption that is recorded in the first quarter of 2006 is due primarily to the recording of the liability component of the Company s performance share awards at fair value, rather than intrinsic value.

During the third quarter of 2006, the Company adopted the provisions outlined under FSP FAS No. 123(R)-3, Transition Election Related to Accounting for the Tax Effects of Share-Based Payment Awards, which discusses accounting for taxes for stock awards using the APIC Pool concept. The Company is not required to adopt this provision until January 1, 2007, one year from the adoption of 123(R); however, it chose early adoption. The Company has made a one time election as prescribed under the FSP to use the shortcut approach to derive the initial windfall tax benefit pool. The Company has chosen to use a one pool approach which combines all awards granted to employees, including non-employee directors.

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The following table illustrates the effect on Net Income and Earnings per Share if the Company had applied the fair value recognition provisions of SFAS No. 123(R) to stock-based employee compensation during the three and nine months ended September 30, 2005:

(In thousands, except per share amounts)		**Three Months Ended September 30, 2005**		**Nine Months Ended September 30, 2005**
Net Income, as reported	$	33,756	$	89,940
Add: Employee stock-based compensation expense, net of related tax effects, included in net income, as reported		2,629		4,217
Deduct: Total stock-based employee compensation expense determined under fair value based method for all awards, net of tax, previously not included in Net Income		(2,799)		(4,866)
Pro forma net income	$	33,586	$	89,291
Earnings per Share:				
Basic - as reported	$	0.69	$	1.84
Basic - pro forma	$	0.69	$	1.83
Diluted - as reported	$	0.68	$	1.81
Diluted - pro forma	$	0.68	$	1.80
Share Count		48,951		48,865
Diluted Share Count		49,665		49,613

Restricted Stock Awards

Restricted stock awards vest either at the end of a three year service period, or on a graded-vesting basis for awards that vest 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.

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 accelerates 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 3.3% based on the Company s ten year history for this type of award to various employee groups.

There were 46,850 restricted stock awards granted to employees in the first nine months of 2006. All of these awards were granted in the first quarter of 2006. These awards vest over a three year service period on a graded-vesting schedule. Compensation expense recorded for all unvested restricted stock awards for the first nine months of 2006 and 2005 is $4.8 million and $4.2 million, respectively. Included in the 2006 expense is $0.5 million related to the immediate expensing of shares granted to retirement-eligible employees. Unamortized expense as of September 30, 2006 for all outstanding restricted stock awards is $5.5 million.

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The following table is a summary of activity of restricted stock awards for the nine months ended September 30, 2006:

Restricted Stock Awards	Shares	Weighted-Average Grant Date Fair Value per share	Weighted-Average Remaining Contractual Term (in years)	Aggregate Intrinsic Value (in thousands) (1)
Non-vested shares outstanding at December 31, 2005	588,465	$ 26.68		
Granted	46,850	47.60		
Vested	(230,743)	21.71		
Forfeited	(3,800)	31.31		
Non-vested shares outstanding at September 30, 2006	**400,772**	**$ 31.92**	**1.7**	**$ 19,209**

(1) *The aggregate intrinsic value of restricted stock awards is calculated by multiplying the closing market price of the Company s stock on September 30, 2006 by the number of non-vested restricted stock awards outstanding.*

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. Due to the immediate vesting of the units and the unknown term of each director, the weighted-average remaining contractual term in years has been omitted from the table below.

The following table is a summary of activity of restricted stock units for the nine months ended September 30, 2006:

Restricted Stock Units	Shares	Weighted-Average Grant Date Fair Value per share	Aggregate Intrinsic Value (in thousands) (1)
Outstanding at December 31, 2005	30,100	$ 31.30	
Granted and fully vested	17,220	50.82	
Issued	(8,600)	31.30	
Forfeited			
Outstanding at September 30, 2006	**38,720**	**$ 39.98**	**$ 1,856**

(1) *The intrinsic value of restricted stock units is calculated by multiplying the closing market price of the Company s stock on September 30, 2006 by the number of outstanding restricted stock units as of September 30, 2006.*

As shown in the table above, 17,220 restricted stock units were granted during the first nine months of 2006. The compensation cost, which reflects the total fair value of these units, recorded in the second quarter of 2006 is $0.9 million.

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Stock Options

During the first nine months of 2006, 30,000 stock options were granted to two incoming non-employee directors of the Company. All of these stock options were granted in the first quarter of 2006. The grant date fair value of a stock option is calculated by using a Black-Scholes model. Compensation cost is recorded based on a graded-vesting schedule as the options 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. Stock options have a maximum contractual term of five years. No forfeiture rate is assumed for stock options granted to directors due to the forfeiture rate history for these types of awards for this group of individuals. Option awards are generally granted with an exercise price equal to the fair market price of the Company s stock at the date of grant. No stock options were granted in the first nine months of 2005.

Compensation expense recorded during the first nine months of 2006 for these stock options is $0.2 million. Since the Company had not yet adopted SFAS No. 123(R) in the first nine months of 2005, stock options were not expensed through the statement of operations during 2005 and no compensation expense was recorded. Unamortized expense as of September 30, 2006 for all outstanding stock options is $0.3 million. The weighted average period over which this compensation will be recognized is approximately 2.4 years.

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

	Three and Nine Months Ended September 30, 2006
Weighted Average Value per Option Granted During the Period [1]	**$ 14.65**
Assumptions	
Stock Price Volatility	**31.5%**
Risk Free Rate of Return	**4.6%**
Expected Dividend	**0.3%**
Expected Term (in years)	**4.0**

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

The following table is a summary of activity of stock options for the nine months ended September 30, 2006:

Stock Options	Shares	Weighted-Average Exercise Price	Weighted-Average Remaining Contractual Term (in years)	Aggregate Intrinsic Value (in thousands) [1]
Outstanding at December 31, 2005	913,348	$ 15.32		
Granted	30,000	47.60		
Exercised	(237,273)	15.19		
Forfeited or Expired	(900)	18.20		
Outstanding at September 30, 2006	**705,175**	**$ 16.74**	**1.3**	**$ 21,996**
Options Exercisable at September 30, 2006	**675,175**	**$ 15.37**	**1.1**	**$ 21,986**

[1] *The intrinsic value of a stock option is the amount by which the current market value of the underlying stock exceeds the exercise price of the option.*

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At September 30, 2006, the exercise price range for outstanding options is $12.84 to $47.60 per share. The following tables provide more information about the options by exercise price.

Options with exercise prices between $12.84 and $15.00 per share:

Options Outstanding

Number of Options	159,400
Weighted Average Exercise Price	$ 12.84
Weighted Average Contractual Term (in years)	0.4

Options Exercisable

Number of Options	159,400
Weighted Average Exercise Price	$ 12.84
Weighted Average Contractual Term (in years)	0.4

Options with exercise prices between $15.01 and $30.00 per share:

Options Outstanding

Number of Options	515,775
Weighted Average Exercise Price	$ 16.15
Weighted Average Contractual Term (in years)	1.4

Options Exercisable

Number of Options	515,775
Weighted Average Exercise Price	$ 16.15
Weighted Average Contractual Term (in years)	1.4

Options with exercise prices between $30.01 and $47.60 per share:

Options Outstanding

Number of Options	30,000
Weighted Average Exercise Price	$ 47.60
Weighted Average Contractual Term (in years)	4.4

None of the options with exercise prices between $30.01 and $47.60 are exercisable as of September 30, 2006.

In September 2006, the SEC Staff issued a letter summarizing their views regarding the backdating of stock options. The letter discusses the date that is to be used as the measurement date for options in order to value the exercise price of the options. It also discusses the documentation that should be available to support award grant dates. The Company has reviewed its stock option granting practices and has found no instances of backdating. Further, as required under the Company s incentive plans, the stock option grant date is the date on which the Compensation Committee and/or Board of Directors approves the award. Company management is given no discretion to choose the grant date. The Company maintains Compensation Committee and/or Board of Directors minutes and other records to support the grant dates of its options.

Stock Appreciation Rights

On February 23, 2006, the Company granted 132,800 stock appreciation rights (SARs) to employees. These awards allow the employee to receive any intrinsic value over the $47.60 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 of September 30, 2006, there are 132,800 SARs outstanding. The aggregate intrinsic value of

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these awards is less than $0.1 million at September 30, 2006. As these SARs are paid out in stock, rather than in cash, the Company calculates the fair value in the same manner as stock options, by using a Black-Scholes model.

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

	Three and Nine Months Ended September 30, 2006
Weighted Average Value per Stock Appreciation Right Granted During the Period [(1)]	$ 14.19
Assumptions	
Stock Price Volatility	31.6%
Risk Free Rate of Return	4.6%
Expected Dividend	0.3%
Expected Term (in years)	3.75

(1) *Calculated using the Black-Scholes fair value based method.*

Compensation expense recorded during the first nine months of 2006 for these SARs is $0.7 million. As no SARs were outstanding in the first nine months of 2005, no compensation expense was recorded for this type of award. In addition, all SARs were unvested at September 30, 2006. Unamortized expense as of September 30, 2006 for all outstanding SARs is $1.2 million which will be recognized over the next 2.4 years.

Performance Share Awards

The Company grants two types of performance share awards to employees. Certain of these awards 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 vesting performance period. Depending on the Company s performance, employees may earn up to 100% of the award in common stock, and an additional 100% of the award in cash. A new type of award has been granted in 2006 that measures the Company s performance based on internal metrics rather than a peer group. 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 three performance criteria set by the Company s Compensation Committee. An employee will earn one-third of the award granted for each internal metric performance criteria 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.

Both of these types of awards vest at the end of a designated three year performance period. For all awards granted to employees before and after January 1, 2006, an annual forfeiture rate ranging from 0% to 5.0% has been assumed based on the Company s history for this type of award to various employee groups.

On February 23, 2006, the Board of Directors granted a series of 89,850 performance share awards with performance conditions and 52,900 performance share awards with market conditions to employees of the Company. The performance period for both of these awards commences January 1, 2006 and ends December 31, 2008.

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 is 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.

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The three primary inputs for the Monte Carlo model are the risk-free rate, volatility of returns and correlation in stock price movement. 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 is set equal to the annualized daily volatility measured over a historic four year period ending on the reporting date. A sample of correlation statistics were reviewed between the Company and its peers and the average ranged between 87% and 93%.

The following assumptions were used as of September 30, 2006 for the Monte Carlo model to value the liability components of the peer group measured performance share awards. The equity portion of the award granted in 2006 has already been valued on the date of grant using the Monte Carlo model and this portion is not marked to market.

	As of September 30, 2006
Risk Free Rate of Return	4.7% - 4.9%
Stock Price Volatility	32.8%
Correlation in stock price movement	90%

The Monte Carlo value per share for the liability for performance share awards at September 30, 2006 ranged from $1.91 to $27.50. The long-term liability, included in Other Liabilities in the Condensed Consolidated Balance Sheet, and short-term liability, included in Accrued Liabilities in the Condensed Consolidated Balance Sheet, for performance share awards at September 30, 2006 is $1.6 million and $0.4 million, respectively.

The following table is a summary of activity of performance share awards for the nine months ended September 30, 2006:

Performance Share Awards	**Shares**	**Weighted-Average Grant Date Fair Value per share [1]**	**Weighted-Average Remaining Contractual Term (in years)**	**Aggregate Intrinsic Value (in thousands) [2]**
Non-vested shares outstanding at December 31, 2005	330,850	$ 24.30		
Granted	142,750	43.35		
Vested				
Forfeited	(2,750)	29.08		
Non-vested shares outstanding at September 30, 2006	**470,850**	**$ 30.05**	**1.2**	**$ 22,568**

(1) *The fair value figures in this table represent the fair value of the equity component of the performance share awards.*

(2) *The aggregate intrinsic value of performance share awards is calculated by multiplying the closing market price of the Company s stock on September 30, 2006 by the number of non-vested performance share awards outstanding.*

Total unamortized compensation cost related to the equity component of performance shares at September 30, 2006 is $6.1 million and will be recognized over the next 2.0 years, as computed by using the weighted average of the time in years remaining to recognize unamortized expense. Total compensation cost recognized for both the equity and liability components of performance share awards during the nine months ended September 30, 2006 and 2005 is $5.2 million and $2.6 million, respectively.

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12. CAPITAL STOCK

Increase in Authorized Shares

On May 4, 2006, the stockholders of the Company approved an increase in the authorized number of shares of common stock from 80 million to 120 million shares. The Company correspondingly increased the number of shares of Series A Junior Participating Preferred Stock reserved for issuance from 800,000 to 1,200,000. The shares of Series A Junior Participating Preferred Stock are issuable pursuant to the Rights Agreement between the Company and The Bank of New York, as Rights Agent.

Treasury Stock

In August 1998, the Company announced that its Board of Directors authorized the repurchase of two million shares of the Company s common stock in the open market or in negotiated transactions. As a result of the 3-for-2 stock split effected in March 2005, this figure was adjusted to three million shares. All purchases executed to date have been through open market transactions. There is no expiration date associated with the authorization to repurchase securities of the Company.

During the nine months ended September 30, 2006, the Company repurchased 1,088,500 shares with a weighted average price per share of $42.71 for a total cost of approximately $46.5 million. All of the repurchases occurred during the second and third quarters. The repurchased shares are held as treasury stock. Since the authorization date, the Company has repurchased 2,602,350 shares, or 87% of the total shares authorized for repurchase at September 30, 2006, for a total cost of approximately $85.7 million.

On October 26, 2006, the Company announced that its Board of Directors increased the number of shares of the Company s common stock authorized for repurchase by an additional two million shares.

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Report of Independent Registered Public Accounting Firm

To the Board of Directors and Stockholders of

Cabot Oil & Gas Corporation:

We have reviewed the accompanying condensed consolidated balance sheet of Cabot Oil & Gas Corporation and its subsidiaries (the Company) as of September 30, 2006, and the related condensed consolidated statement of operations for each of the three and nine month periods ended September 30, 2006 and 2005 and the condensed consolidated statement of cash flows for the nine month periods ended September 30, 2006 and 2005. 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, 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 have previously audited in accordance with the standards of the Public Company Accounting Oversight Board (United States) the consolidated balance sheet as of December 31, 2005 and the related consolidated statements of operations, comprehensive income, stockholders equity, and cash flows for the year then ended, management s assessment of the effectiveness of the Company s internal control over financial reporting as of December 31, 2005 and the effectiveness of the Company s internal control over financial reporting as of December 31, 2005; and in our report dated March 6, 2006, which included an explanatory paragraph related to the adoption of Statement of Financial Accounting Standards No. 143, Accounting for Asset Retirement Obligations, we expressed unqualified opinions thereon. The consolidated financial statements and management s assessment of the effectiveness of internal control over financial reporting referred to above are not presented herein. In our opinion, the information set forth in the accompanying condensed consolidated balance sheet information as of December 31, 2005, is fairly stated in all material respects in relation to the consolidated balance sheet from which it has been derived.

As discussed in Notes 1 and 11 to the condensed consolidated financial statements, effective January 1, 2006, the Company adopted Statement of Financial Accounting Standards No. 123(R), Share Based Payment (revised 2004).

/s/ PricewaterhouseCoopers LLP

Houston, Texas
October 27, 2006

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

The following review of operations for the three and nine month periods ended September 30, 2006 and 2005 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 Form 10-K for the year ended December 31, 2005.

Overview

Natural gas revenues increased by $99.4 million, or 29%, for the nine months ended September 30, 2006 as compared to the nine months ended September 30, 2005. The increase is due to higher realized natural gas prices as well as increased production in the Gulf Coast, East and Canada. Oil revenues increased by $23.0 million, or 40%, for the first nine months of 2006 as compared to the first nine months of 2005. This increase is primarily due to an increase in oil prices in the first nine months of 2006 as compared to the first nine months of 2005. Additionally, crude oil revenues for the first nine months of 2005 included an unrealized loss on crude oil derivatives of $1.9 million, and there is no unrealized impact in the first nine months of 2006. Somewhat offsetting the crude oil price increase and the change in the unrealized loss on crude oil derivatives is the decrease in crude oil production of approximately 10% in the first nine months of 2006.

Our realized natural gas price for the first nine months of 2006 was $7.22 per Mcf, 17% higher than the $6.16 per Mcf price realized in the same period of the prior year. Our realized crude oil price was $66.42 per Bbl, 51% higher than the $43.92 per Bbl price realized in the same period of the prior year. These realized prices are impacted by realized gains and losses resulting from commodity derivatives. For information about the impact of these derivatives on realized prices, refer to the Results of Operations section. Commodity prices are determined by 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 demands, overall economic activity, weather, pipeline capacity constraints, storage levels, basis differentials and other factors. As a result, we cannot accurately predict future natural gas, NGL and crude oil prices and, therefore, cannot accurately predict revenues.

For the nine months ended September 30, 2006, we produced 67.8 Bcfe compared to production of 62.9 Bcfe for the comparable period of the prior year. Natural gas production was 60.5 Bcf and oil production was 1,209 Mbbls. Natural gas production increased by approximately 10% when compared to the comparable period of the prior year, which had production of 54.8 Bcf. Our East region improved natural gas production with the success of our drilling program. The Gulf Coast region also had increased production from the prior year period due to a successful 2006 drilling program as well as an offshore well that commenced production in the second quarter of 2006. In addition, production in Canada increased as a result of the continued drilling success, with the initiation of production in the Narraway area and additional production volume from the Hinton field. These increases are partially offset by reduced production in our West region as a result of pipeline and compression curtailments and natural production declines. Oil production decreased by 137 Mbbls from 1,346 Mbbls in the first nine months of 2005 to 1,209 Mbbls produced in the first nine months of 2006. Oil production increased in the West, remained flat in the East and decreased in the Gulf Coast and Canada. The primary reason for the production decrease is from a decrease in Gulf Coast production due to the continued natural decline of the CL&F lease in south Louisiana, which was sold in September 2006.

We had net income of $289.0 million, or $5.95 per share, for the nine months ended September 30, 2006 compared to net income of $89.9 million, or $1.84 per share, for the comparable period of the prior year. The increase in net income is primarily due to the gain of $229.7 million ($143.6 million, net of tax) recorded in the third quarter of 2006 related to the disposition of our offshore and certain south Louisiana properties described below. In addition, net income is higher due to increased natural gas and oil production revenues, as discussed above. Offsetting these increases in income were increases in the first nine months of 2006 as compared to the first nine months of 2005 in total operating expenses of $47.0 million as well as income tax expense of $112.3 million. Income taxes increased primarily as a result of the gain on the disposition of properties that occurred during the third quarter of 2006.

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In addition to production volumes and commodity prices, finding and developing sufficient amounts of crude oil and natural gas reserves at economical costs are critical to our long-term success. For the fourth quarter of 2006, we expect to spend approximately $100 million in capital and exploration expenditures. Our annual capital budget of approximately $500 million was increased by approximately $104 million from the $396 million figure previously reported in our Form 10-K in order to reflect increased drilling costs as well as new projects. Of the $104 million increase, approximately $60 million will be funded from the proceeds from the sale of the offshore and south Louisiana assets. For the nine months ended September 30, 2006, approximately $401.0 million of capital and exploration expenditures have been invested in our exploration and development efforts.

During the nine months ended September 30, 2006, we drilled 301 gross wells (278 development, 14 exploratory and 9 extension wells) with a success rate of 97% compared to 229 gross wells (207 development, 18 exploratory and 4 extension wells) with a success rate of 95% for the comparable period of the prior year. As disclosed in our Annual Report on Form 10-K for the year ended December 31, 2005, for the full year of 2006, we plan to drill approximately 391 gross wells compared to 316 gross wells in 2005.

We remain focused on our strategies of pursuing lower risk drilling opportunities that provide more predictable results and selectively pursuing impact exploration opportunities as we accelerate drilling on our accumulated acreage position. In the current year we have allocated our planned program for capital and exploration expenditures among our various operating regions. We believe these strategies are appropriate in the current industry environment and will continue to add shareholder value over the long term.

On September 29, 2006, we completed the sale of our offshore portfolio and certain south Louisiana properties to Phoenix Exploration Company LP (Phoenix) for a gross sales price of $340.0 million. The properties sold included proved reserves of approximately 98 Bcfe as of the August 1, 2006 effective date, including 68 Bcfe of proved reserved recorded as of December 31, 2005, and had average daily production for the nine months ended September 30, 2006 of 47.4 Mmcfe.

Pursuant to the Asset Purchase Agreement (the Agreement) dated August 25, 2006, the gross sales price is to be offset by the net cash flow (as defined in the Agreement) from operation of the properties from August 1, 2006 and other purchase price adjustments, if any. The net proceeds from the sale are expected to be used to add funding to our capital program, repurchase shares of common stock, repay outstanding debt under the revolving credit facility and pay taxes related to the transaction. Also pursuant to the Agreement, we entered into certain commodity price swaps on behalf of Phoenix. At closing on September 29, 2006, these derivative instruments were assigned to Phoenix, and we were released from all rights and obligations with respect thereto. There was no ultimate impact on our financial statements due to the existence of these swaps.

Through September 30, 2006, the Company had received approximately $321.4 million in net proceeds from this sale of our offshore and south Louisiana properties. Net proceeds of $321.4 million reflects the $340.0 million gross sales price, reduced by purchase price adjustments of $3.1 million as well as consents and preferential rights expected to be settled in the fourth quarter of 2006 of $15.5 million. A net gain of $229.7 million ($143.6 million, net of tax) is recorded in the Statement of Operations for the third quarter of 2006 and an additional gain of approximately $12.0 million is expected to be recognized in the fourth quarter of 2006, in connection with the closing of certain property sales to Phoenix for which third party consents had not been obtained as of September 30, 2006 and sales to other parties that executed their contractual preferential rights.

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

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Financial Condition

Capital Resources and Liquidity

Our primary sources of cash for the nine months ended September 30, 2006 are from funds generated from the sale of natural gas and crude oil production as well as proceeds from the sale of our offshore and certain south Louisiana properties. 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 subject to 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, have influenced prices throughout the recent years. Working capital is also substantially influenced by these variables. Fluctuation 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. Cash flows provided by operating activities were primarily used to fund exploration and development expenditures, purchase treasury stock and pay dividends. See below for additional discussion and analysis of cash flow.

	Nine Months Ended September 30,	
(In thousands)	**2006**	**2005**
Cash Flows Provided by Operating Activities	**$ 356,050**	$ 247,111
Cash Flows Used in Investing Activities	**(61,605)**	(287,904)
Cash Flows Provided by Financing Activities	**17,052**	33,954
Net Increase / (Decrease) in Cash and Cash Equivalents	**$ 311,497**	$ (6,839)

***Operating Activities*.** Net cash provided by operating activities in the first nine months of 2006 increased by $108.9 million over the comparable period in 2005. This increase is primarily due to higher commodity prices and, to a lesser extent, increased equivalent production. Key components impacting net operating cash flows are commodity prices, production volumes and operating costs. Average realized natural gas prices increased 17% over the 2005 period, while crude oil realized prices increased 51% over the same period. Equivalent production volumes increased by approximately 8% in the first nine months of 2006 compared to the comparable period in 2005. While we expect 2006 actual production to exceed 2005 levels, 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.

***Investing Activities*.** The primary uses of cash in investing activities are capital spending and exploration expense. Cash flows used for investments in capital and exploration expenditures is $384.6 million in the first nine months of 2006 compared to $288.9 used in the first nine months of 2005. This increase of $95.7 million in investments in capital and exploration expenses is entirely offset by the increase of $322.0 million in proceeds from the sale of assets, primarily as a result of the sale of our offshore and certain south Louisiana properties, resulting in an overall decrease of $226.3 million in net cash used in investing activities for the first nine months of 2006 compared to the first nine months of 2005. We establish the budget for these amounts based on our current estimate of future commodity prices. Due to the volatility of commodity prices, our capital expenditures budget may be periodically adjusted during any given year. The increase from 2005 to 2006 in cash flows used in capital spending and exploration expense is primarily due to an increase in drilling activity in response to higher commodity prices.

***Financing Activities*.** Cash flows provided by financing activities are $17.1 million for the nine months ended September 30, 2006 and are comprised of payments made to purchase treasury stock and dividend payments. Offsetting these cash uses were inflows from a net increase in borrowings under our revolving credit facility, the exercise of stock options and the tax benefit received from stock-based compensation. Cash flows provided by financing activities were $34.0 million for the nine months ended September 30, 2005. Cash flows provided by financing activities in the first nine months of 2005 were the result of an increase in book overdrafts, borrowings under our revolving credit facility and proceeds from the exercise of stock options, partially offset by dividend payments and purchases of treasury stock.

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At September 30, 2006, we had $150 million of debt outstanding under our credit facility. Subsequent to the end of the third quarter, on October 2, 2006, we repaid the entire $150 million outstanding balance with proceeds from the sale of assets. The credit facility provides for an available credit line of $250 million, which can be expanded up to $350 million, either with the existing banks or new banks. 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. We strive to manage our debt at a level below the available credit line in order to maintain excess borrowing capacity. Management believes that we have the ability to finance through new debt or equity offerings, if necessary, our capital requirements, including potential acquisitions.

In August 1998, we announced that our Board of Directors authorized the repurchase of two million shares of our common stock in the open market or in negotiated transactions. As a result of the 3-for-2 stock split effected in March 2005, this figure was adjusted to three million shares. During the first nine months of 2006, we repurchased 1,088,500 shares of our common stock at a weighted average price of $42.71. All of the repurchases occurred during the second and third quarters. All purchases executed to date have been through open market transactions. On October 26, 2006, we announced that our Board of Directors increased the number of shares of our common stock authorized for repurchase by an additional two million shares. There is no expiration date associated with the authorization to repurchase our securities. The maximum number of shares that may yet be purchased under the plan as of September 30, 2006 was 397,650. See Unregistered Sales of Equity Securities Issuer Purchases of Equity Securities in Item 2 of Part II of this quarterly report.

Capitalization

Our capitalization information is as follows:

(In millions)	**September 30, 2006**	December 31, 2005
Debt [1]	**$ 400.0**	$ 340.0
Stockholders Equity	**909.8**	600.2
Total Capitalization	**$ 1,309.8**	$ 940.2
Debt to Capitalization	**31%**	36%
Cash and Cash Equivalents	**$ 322.1**	$ 10.6

(1) *Includes $20.0 million of current portion of long-term debt at both September 30, 2006 and December 31, 2005. Includes $150 million and $90 million of borrowings under our revolving credit facility at September 30, 2006 and December 31, 2005, respectively. The $150 million outstanding balance at September 30, 2006 was repaid on October 2, 2006.*

During the nine months ended September 30, 2006, we paid dividends of $5.8 million on our common stock. A regular dividend of $0.04 per share of common stock has been declared for each quarter since we became a public company in 1990.

Increase in Authorized Shares

On May 4, 2006, our stockholders approved an increase in the authorized number of shares of our common stock from 80 million to 120 million shares. We correspondingly increased the number of shares of Series A Junior Participating Preferred Stock reserved for issuance from 800,000 to 1,200,000. The shares of Series A Junior Participating Preferred Stock are issuable pursuant to our Rights Agreement with The Bank of New York, as Rights Agent.

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Capital and Exploration Expenditures

On an annual basis, we generally fund most of our capital and exploration activities, excluding 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, 2006 and 2005.

	Nine Months Ended September 30,	
(In millions)	**2006**	**2005**
Capital Expenditures		
Drilling and Facilities	**$ 300.6**	$ 163.2
Leasehold Acquisitions	**35.4**	15.6
Pipeline and Gathering	**16.4**	12.0
Other	**2.0**	1.1
	354.4	191.9
Proved Property Acquisitions	**6.6**	60.4
Exploration Expense	**40.0**	47.4
Total	**$ 401.0**	$ 299.7

During the nine months ended September 30, 2005, we spent $60.4 million on producing property acquisitions. Of this amount, $59.4 million was spent in the third quarter of 2005. During the third quarter of 2005, we closed on two large producing property acquisitions for interests in fields in the Gulf Coast region. For the McCampbell field acquisition, we spent $41.2 million. The Vernon field acquisition was $18.0 million. During the nine months ended September 30, 2006, primarily in the third quarter, we spent $6.6 million on producing property acquisitions in the Gulf Coast region.

We plan to drill approximately 391 gross wells in 2006. This drilling program includes approximately $500 million in total capital and exploration expenditures. See the Overview discussion for additional information regarding the current year drilling program. The increase in our leasehold acquisitions expense from September 30, 2005 to September 30, 2006 is the result of several new exploratory resource areas in all regions. We will continue to assess the natural gas and crude oil price environment and may increase or decrease the capital and exploration expenditures accordingly.

Contractual Obligations

During the nine months ended September 30, 2006, certain events have occurred changing the amounts previously reported in our contractual obligations table for drilling rig commitments and firm gas transportation agreements in our Annual Report on Form 10-K for the year ended December 31, 2005.

Our firm gas transportation agreements provide firm transportation capacity rights on pipeline systems in Canada, the West and the East regions. The amount of transportation demand charges under these agreements that we are estimated to pay, regardless of the amount of pipeline capacity we utilize, has decreased by approximately $3.8 million over the total remaining terms of these contracts, which range from less than one year to 21 years. This is due to rate changes and released volumes on certain contracts, partially offset by increased charges as a result of new contracts entered into in Canada. Demand charges for 2006 are expected to be $7.1 million, a decrease of $4.6 million from the $11.7 million figure previously disclosed. Future obligations that we expect to pay starting in 2007 under these firm gas transportation agreements in effect at September 30, 2006 have increased by $0.8 million to $82.9 million.

Drilling rig commitments reported in the Annual Report on Form 10-K for the year ended December 31, 2005 totaled $104.3 million. As a result of an additional contract entered into during 2006, renewals of existing contracts and increases in daily rates due to increased contractor expenses for certain rigs, our total commitments have increased by $11.3 million.

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For further information, please refer to Firm Gas Transportation Agreements and 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, 2005, for further discussion of our critical accounting policies.

Effective January 1, 2006, we adopted the accounting policies described in SFAS No. 123(R), Share Based Payment (revised 2004). We chose to use the modified prospective method of transition, and accordingly, no adjustments to prior period financial statements have been made. Prior to January 1, 2006, we accounted for stock-based compensation in accordance with the intrinsic value based method prescribed by Accounting Principles Board Opinion (APB) No. 25, Accounting for Stock Issued to Employees. In addition, SFAS No. 123, Accounting for Stock-Based Compensation, as amended by SFAS No. 148, Accounting for Stock-Based Compensation Transition and Disclosure, outlines a fair value based method of accounting for stock options or similar equity instruments.

One primary difference in our method of accounting after the adoption of SFAS No. 123(R) is that unvested stock options will now be expensed as a component of Stock-Based Compensation cost in the General and Administrative Expense line item of the Condensed Consolidated Statement of Operations. This expense will be based on the fair value of the award at the original grant date and will be recognized over the vesting period. Prior to the adoption of SFAS No. 123(R), we included this amount as a pro-forma disclosure in the Notes to the Condensed Consolidated Financial Statements. The expense resulting from the expensing of stock options is $0.2 million for the nine months ended September 30, 2006. Another change relates to the accounting for our performance share awards. Certain of these awards are now accounted for by bifurcating the equity and liability components. A Monte Carlo model is used to value the liability component, rather than accounting for the award using the average closing stock price at the end of each reporting period. All other awards are accounted for in substantially the same way as they were or would have been in prior periods, with the exception of the differences noted below.

Other differences in the way we account for stock-based compensation after January 1, 2006, result from the application of a forfeiture rate to all grants rather than recording actual forfeitures as they occur. We are now required to estimate forfeitures on all equity-based compensation and adjust periodic expense. Upon adoption, we did not record a cumulative effect adjustment for these forfeitures as the amount is immaterial. In addition, this change in accounting for forfeitures results in an immaterial change in overall compensation cost for the nine months ended September 30, 2006. Furthermore, we are required to immediately expense certain awards to retirement-eligible employees depending on the structure of each individual plan. The retirement-eligibility provision only applies to new grants that were awarded after January 1, 2006. The total expense that we immediately recognized related to restricted stock awards granted to retirement-eligible employees in the first nine months of 2006 is $0.5 million.

We issued stock appreciation rights to executive employees for the first time during the first quarter of 2006. The grant date fair value of these awards is measured using a Black-Scholes model and compensation cost is expensed over the three year graded-vesting service period. Expense related to these awards is $0.7 million, before the effect of taxes, for the first nine months of 2006. In addition, a new type of performance share was issued to employees. These awards measure our performance based on three internal metrics rather than a peer group s stock performance used for our other performance share awards. These awards cliff vest at the end of the three year service period. Compensation cost related to these new internal-metric based performance share awards granted to employees is $1.0 million, before the effect of taxes, for the first nine months of 2006. In addition, we incurred a $0.4 million, net of tax, cumulative effect charge in the first quarter of 2006 as a result of changes made in our accounting for performance shares. For further information on the accounting for these and our other stock-based compensation awards, please refer to Notes 1 and 11 to the Notes to the Condensed Consolidated Financial Statements.

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During the third quarter of 2006, we adopted the provisions outlined under FSP FAS No. 123(R)-3, Transition Election Related to Accounting for the Tax Effects of Share-Based Payment Awards, which discusses accounting for taxes for stock awards using the APIC Pool concept. We have made a one time election as prescribed under the FSP to use the shortcut approach to derive the initial windfall tax benefit pool. We chose to use a one pool approach which combines all awards granted to employees, including non-employee directors.

Our Compensation Committee of our Board of Directors made one modification to our stock option awards in 2005. It approved the acceleration to December 15, 2005 of the vesting of 198,799 unvested stock options awarded in February 2003 under our Second Amended and Restated 1994 Long-Term Incentive Plan and 24,500 unvested stock options awarded in April 2004 under our 2004 Incentive Plan.

The 198,799 shares awarded to employees under the 1994 plan at an exercise price of $15.32 would have vested in February 2006. The 24,500 shares awarded to non-employee directors under the 2004 plan at an exercise price of $23.32 would have vested 12,250 shares in each of April 2006 and April 2007. The decision to accelerate the vesting of these unvested options, which we believed to be in the best interest of our shareholders and employees, was made solely to reduce compensation expense and administrative burden associated with our adoption of SFAS No. 123(R). The accelerated vesting of the options did not have an impact on our results of operations or cash flows for 2005. The acceleration of vesting reduced our compensation expense related to these options by approximately $0.2 million for 2006.

Results of Operations

Third Quarters of 2006 and 2005 Compared

We reported net income in the third quarter of 2006 of $189.0 million, or $3.92 per share. During the corresponding quarter of 2005, we reported net income of $33.8 million, or $0.69 per share. Net income increased in the third quarter by $155.2 million, primarily due to an increase in operating income of $245.7 million from $59.0 million in the third quarter of 2005 to $304.7 million in the third quarter of 2006. This increase was primarily due to the $229.7 million ($143.6 million net of tax) gain on the sale of offshore and certain south Louisiana assets recorded in the third quarter of 2006 as well as an increase in natural gas and oil production revenues. This income increase is partially offset by an increase of $88.8 million in income tax expense as well as an increase in operating expenses of $7.0 million.

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Natural Gas Production Revenues

Our average total company realized natural gas production sales price, including the realized impact of derivative instruments, is $6.76 per Mcf for the three months ended September 30, 2006 compared to $6.77 per Mcf for the comparable period of the prior year. These prices include the realized impact of derivative instrument settlements which increased the price by $0.41 per Mcf in 2006 and reduced the price by $1.26 per Mcf in 2005. The following table excludes the unrealized loss from the change in derivative fair value of $0.4 million for the three months ended September 30, 2005. There is no unrealized impact from the change in derivative fair value for the three months ended September 30, 2006. The unrealized change in fair value has been included in Natural Gas Production Revenues in the Statement of Operations.

	Three Months Ended September 30,		Variance	
	2006	**2005**	**Amount**	**Percent**
Natural Gas Production (Mmcf)				
Gulf Coast	**8,029**	6,333	1,696	27%
West	**6,124**	5,961	163	3%
East	**5,930**	5,453	477	9%
Canada	**652**	264	388	147%
Total Company	**20,735**	18,011	2,724	15%
Natural Gas Production Sales Price ($/Mcf)				
Gulf Coast	**$ 7.13**	$ 6.67	$ 0.46	7%
West	**$ 5.84**	$ 5.91	$ (0.07)	(1)%
East	**$ 7.41**	$ 7.75	$ (0.34)	(4)%
Canada	**$ 5.09**	$ 8.04	$ (2.95)	(37)%
Total Company	**$ 6.76**	$ 6.77	$ (0.01)	
Natural Gas Production Revenue (in thousands)				
Gulf Coast	**$ 57,216**	$ 42,253	$ 14,963	35%
West	**35,770**	35,229	541	2%
East	**43,958**	42,280	1,678	4%
Canada	**3,317**	2,123	1,194	56%
Total Company	**$ 140,261**	$ 121,885	$ 18,376	15%
Price Variance Impact on Natural Gas Production Revenue *(in thousands)*				
Gulf Coast	**$ 3,723**			
West	**(415)**			
East	**(2,021)**			
Canada	**(1,925)**			
Total Company	**$ (638)**			
Volume Variance Impact on Natural Gas Production Revenue *(in thousands)*				
Gulf Coast	**$ 11,240**			
West	**956**			
East	**3,699**			
Canada	**3,119**			
Total Company	**$ 19,014**			

The increase in Natural Gas Production Revenue is primarily due to the increase in natural gas production. Production is higher in all regions in the third quarter of 2006 compared to the third quarter of 2005. Increased production is primarily the result of the increased capital program in

2005 and 2006 and timing of initial production from the drilling program. Prices were lower overall quarter over quarter for the Company. The increase in production and decrease in the realized natural gas price resulted in a net revenue increase of $18.4 million, excluding the unrealized impact of derivative instruments. For the quarter ended September 30, 2006, natural gas volumes from the properties sold in the third quarter disposition were 2,952 Mmcf and natural gas revenues from those properties were approximately $20.2 million.

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Brokered Natural Gas Revenue and Cost

	Three Months Ended September 30, 2006	2005	Variance Amount	Percent
Sales Price ($/Mcf)	**$ 6.96**	$ 9.41	$ (2.45)	(26)%
Volume Brokered (Mmcf)	**2,453**	1,994	459	23%
Brokered Natural Gas Revenues (in thousands)	**$ 17,075**	$ 18,756		
Purchase Price ($/Mcf)	**$ 6.23**	$ 8.30	$ (2.07)	(25)%
Volume Brokered (Mmcf)	**2,453**	1,994	459	23%
Brokered Natural Gas Cost (in thousands)	**$ 15,282**	$ 16,550		
Brokered Natural Gas Margin (in thousands)	**$ 1,793**	$ 2,206	$ (413)	(19)%

(in thousands)	
Sales Price Variance Impact on Revenue	**$ (6,000)**
Volume Variance Impact on Revenue	**4,319**
	$ (1,681)

(in thousands)	
Purchase Price Variance Impact on Purchases	**$ 5,078**
Volume Variance Impact on Purchases	**(3,810)**
	$ 1,268

The decreased brokered natural gas margin of $0.4 million is driven by decreased commodity prices for the third quarter of 2006 compared to the third quarter of 2005. Partially offsetting this decrease is an increase in the volumes brokered in the third quarter of 2006 over the same period in the prior year.

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Crude Oil and Condensate Revenues

Our average total company realized crude oil sales price is $69.80 per Bbl for the third quarter of 2006. There is no realized impact of derivative instruments in the third quarter of 2006. Our average total company realized crude oil sales price, including the realized impact of derivative instruments, is $46.05 per Bbl for the third quarter of 2005. The 2005 price includes the realized impact of derivative instrument settlements which reduced the price by $14.59 per Bbl. The following table excludes the unrealized gain from the change in derivative fair value of $2.0 million for the third quarter of 2005. There is no unrealized impact from the change in derivative fair value for the third quarter of 2006. The unrealized change in fair value has been included in Crude Oil and Condensate Revenues in the Statement of Operations.

	Three Months Ended September 30,		Variance	
	2006	**2005**	**Amount**	**Percent**
Crude Oil Production (Mbbl)				
Gulf Coast	**319**	364	(45)	(12)%
West	**52**	43	9	21%
East	**6**	7	(1)	(14)%
Canada	**2**	5	(3)	(60)%
Total Company	**379**	419	(40)	(10)%
Crude Oil Sales Price ($/Bbl)				
Gulf Coast	**$ 70.10**	$ 43.93	$ 26.17	60%
West	**$ 68.53**	$ 60.77	$ 7.76	13%
East	**$ 64.67**	$ 59.22	$ 5.45	9%
Canada	**$ 69.53**	$ 52.94	$ 16.59	31%
Total Company	**$ 69.80**	$ 46.05	$ 23.75	52%
Crude Oil Revenue (in thousands)				
Gulf Coast	**$ 22,391**	$ 15,970	$ 6,421	40%
West	**3,565**	2,642	923	35%
East	**379**	440	(61)	(14)%
Canada	**100**	246	(146)	(59)%
Total Company	**$ 26,435**	$ 19,298	$ 7,137	37%
Price Variance Impact on Crude Oil Revenue *(in thousands)*				
Gulf Coast	**$ 8,403**			
West	**404**			
East	**32**			
Canada	**41**			
Total Company	$ 8,880			
Volume Variance Impact on Crude Oil Revenue *(in thousands)*				
Gulf Coast	**$ (1,982)**			
West	**519**			
East	**(93)**			
Canada	**(187)**			
Total Company	**$ (1,743)**			

The increase in the realized crude oil price combined with the decline in production resulted in a net revenue increase of $7.1 million, excluding the unrealized impact of derivative instruments. The decrease in oil production is mainly the result of decreased Gulf Coast production from the continued natural decline of the CL&F lease in south Louisiana, which was sold in the third quarter of 2006. For the quarter ended September 30, 2006, crude oil and condensate volumes from the properties sold in the third quarter disposition were 196 Mbbl and crude oil and condensate revenues from those properties were approximately $13.9 million.

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Impact of Derivative Instruments on Operating Revenues

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

	Three Months Ended September 30,			
	2006		2005	
	Realized	Unrealized	Realized	Unrealized
	(In thousands)			
Operating Revenues - Increase/(Decrease) to Revenue				
Cash Flow Hedges				
Natural Gas Production	$ 8,532	$	$ (22,723)	$ (408)
Crude Oil			(1,165)	(24)
Total Cash Flow Hedges	8,532		(23,888)	(432)
Other Derivative Financial Instruments				
Crude Oil			(4,948)	2,062
Total Other Derivative Financial Instruments			(4,948)	2,062
	$ 8,532	$	$ (28,836)	$ 1,630

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.

Other Operating Revenues

Other operating revenues increased by $0.8 million between the third quarter of 2006 and the third quarter of 2005 primarily due to a decrease in our payout liability associated with a favorable legal ruling in the first quarter of 2006, which correspondingly increased other revenues, as well as an increase in cash received for a net profits interest that originated in 2006.

Operating Expenses

Total costs and expenses from operations increased $7.0 million in the third quarter of 2006 compared to the same period of 2005. The primary reasons for this fluctuation are as follows:

Direct Operations expense increased by $5.6 million over the third quarter of 2005. This is primarily the result of an increase over the prior year quarter in outside operated properties expense, primarily in the Gulf Coast, due to offshore activity, including hurricane repairs. In addition, higher expenses were incurred related to disposal costs, treating, compressors and workovers. These increases were primarily seen in the Gulf Coast region due to additional usage, rates and production in addition to timing. In addition, we incurred higher insurance expenses due to premium increases as well as higher expenses for compensation and personnel related expenses.

Depreciation, Depletion and Amortization increased by $5.5 million in the third quarter of 2006. This is primarily due to increased production for the quarter, an increase in finding costs and an increase in the DD&A rate associated with one field in East Texas as well as the commencement of offshore production in late 2005.

General and Administrative expense increased by $1.0 million in the third quarter of 2006. Third quarter 2005 expense included a credit to miscellaneous expenses for a reversal of a reserve attributable to litigation settled during the quarter. Partially offsetting this increase is a decrease in the third quarter 2006 stock compensation expense of $1.1 million due to the change in accounting for performance share compensation as prescribed by SFAS No. 123(R).

Exploration expense decreased by $3.1 million in the third quarter of 2006, primarily as a result of a decrease in total dry hole expense of $2.1 million, which is primarily comprised of a decrease in dry hole expense in the Gulf Coast region, partially offset by increases in Canada and the West region, as well as decreased geophysical and geological expenses of $1.1 million, primarily in the West.

Brokered Natural Gas Cost decreased by $1.3 million from the third quarter of 2005 to the third quarter of 2006. See the preceding table labeled Brokered Natural Gas Revenue and Cost for further analysis.

Taxes Other Than Income decreased by $0.6 million compared to the third quarter of 2005, primarily due to decreased production taxes as a result of decreased natural gas prices.

Interest Expense, Net

Interest expense, net increased $1.8 million in the third quarter of 2006 due to higher credit facility borrowings as well as an increasing interest rate environment. Weighted average borrowings based on daily balances were approximately $113 million during the third quarter of 2006 compared to $49 million during the third quarter of 2005.

Income Tax Expense

Income tax expense increased by $88.8 million due to a comparable increase in our pre-tax income, primarily as a result of the gain on the sale of assets recorded in the third quarter. The effective tax rate for the third quarter of 2006 and 2005 is 36.5% and 37.1%, respectively. The decrease in the effective tax rate is primarily due to the recognition of a change in the Texas state income tax rate due to a change in the tax law in May 2006. In addition, there was a change in the overall blended state income tax rate due to the sale of certain south Louisiana and offshore properties.

Nine Months of 2006 and 2005 Compared

We reported net income in the first nine months of 2006 of $289.0 million, or $5.95 per share. During the corresponding period of 2005, we reported net income of $89.9 million, or $1.84 per share. Net income increased in the current period by $199.1 million primarily due to an increase in operating income as a result of the gain of $229.7 million ($143.6 million, net of tax) recorded in the third quarter of 2006 related to the disposition of our offshore and certain south Louisiana properties as well as an increase in natural gas and oil production revenues. This increase is partially offset by an increase in total operating expenses of $47.0 million and an increase of $112.3 million in income tax expense. Operating income increased $315.5 million compared to the prior year, from $158.8 million in the first nine months of 2005 to $474.3 million in the first nine months of 2006.

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Natural Gas Production Revenues

Our average total company realized natural gas production sales price, including the realized impact of derivative instruments, is $7.22 per Mcf for the nine months ended September 30, 2006 compared to $6.16 per Mcf for the comparable period of the prior year. These prices include the realized impact of derivative instrument settlements which increased the price by $0.28 per Mcf in 2006 and reduced the price by $0.73 per Mcf in 2005. The following table excludes the unrealized loss from the change in derivative fair value of $0.2 million for the nine months ended September 30, 2005. There is no unrealized impact from the change in derivative fair value for the nine months ended September 30, 2006. The unrealized change in fair value has been included in Natural Gas Production Revenues in the Statement of Operations.

	Nine Months Ended September 30,		Variance	
	2006	**2005**	**Amount**	**Percent**
Natural Gas Production (Mmcf)				
Gulf Coast	**23,881**	21,007	2,874	14%
West	**17,272**	17,337	(65)	
East	**17,581**	15,669	1,912	12%
Canada	**1,778**	818	960	117%
Total Company	**60,512**	54,831	5,681	10%
Natural Gas Production Sales Price ($/Mcf)				
Gulf Coast	**$ 7.41**	$ 6.26	$ 1.15	18%
West	**$ 6.19**	$ 5.38	$ 0.81	15%
East	**$ 8.09**	$ 6.90	$ 1.19	17%
Canada	**$ 6.10**	$ 5.95	$ 0.15	3%
Total Company	**$ 7.22**	$ 6.16	$ 1.06	17%
Natural Gas Production Revenue (in thousands)				
Gulf Coast	**$ 176,888**	$ 131,548	$ 45,340	34%
West	**106,953**	93,229	13,724	15%
East	**142,248**	108,109	34,139	32%
Canada	**10,842**	4,866	5,976	123%
Total Company	**$ 436,931**	$ 337,752	$ 99,179	29%
Price Variance Impact on Natural Gas Production Revenue *(in thousands)*				
Gulf Coast	**$ 27,461**			
West	**14,071**			
East	**20,949**			
Canada	**270**			
Total Company	**$ 62,751**			
Volume Variance Impact on Natural Gas Production Revenue *(in thousands)*				
Gulf Coast	**$ 17,879**			
West	**(347)**			
East	**13,190**			
Canada	**5,706**			
Total Company	**$ 36,428**			

The increase in Natural Gas Production Revenue is due to the increase in natural gas sales prices and, to a lesser extent, the increase in natural gas production. Prices were higher in all regions and production increased in the Gulf Coast, East and Canada. Slightly decreased production in the West is due to natural declines as well as lower production on a small number of non-operated wells. The increase in the total realized natural gas price and production resulted in a net revenue increase of $99.2 million, excluding the unrealized impact of derivative instruments. For the nine months ended September 30, 2006, natural gas volumes from the properties sold in the third quarter disposition were 9,143 Mmcf and natural gas revenues from those properties were approximately $70.9 million.

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Brokered Natural Gas Revenue and Cost

	Nine Months Ended September 30, 2006	2005	Variance Amount	Percent
Sales Price ($/Mcf)	**$ 8.13**	$ 7.82	$ 0.31	4%
Volume Brokered (Mmcf)	**8,292**	7,773	519	7%
Brokered Natural Gas Revenues (in thousands)	**$ 67,389**	$ 60,768		
Purchase Price ($/Mcf)	**$ 7.23**	$ 6.89	$ 0.34	5%
Volume Brokered (Mmcf)	**8,292**	7,773	519	7%
Brokered Natural Gas Cost (in thousands)	**$ 59,924**	$ 53,549		
Brokered Natural Gas Margin (in thousands)	**$ 7,465**	$ 7,219	$ 246	3%

(in thousands)	
Sales Price Variance Impact on Revenue	**$ 2,562**
Volume Variance Impact on Revenue	**4,059**
	$ 6,621

(in thousands)	
Purchase Price Variance Impact on Purchases	**$ (2,799)**
Volume Variance Impact on Purchases	**(3,576)**
	$ (6,375)

The increased brokered natural gas margin of $0.2 million is driven by an increase in brokered volumes partially offset by an increased purchase cost that outpaced the increase in sales price.

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Crude Oil and Condensate Revenues

Our average total company realized crude oil sales price is $66.42 per Bbl for the first nine months of 2006. There is no realized impact of derivative instruments in the first nine months of 2006. Our average total company realized crude oil sales price, including the realized impact of derivative instruments, is $43.92 per Bbl for the first nine months of 2005. The 2005 price includes the realized impact of derivative instrument settlements which reduced the price by $8.93 per Bbl. The following table excludes the unrealized loss from the change in derivative fair value of $1.9 million for the first nine months of 2005. There is no unrealized impact from the change in derivative fair value for the first nine months of 2006. The unrealized change in fair value has been included in Crude Oil and Condensate Revenues in the Statement of Operations.

	Nine Months Ended September 30,		Variance	
	2006	**2005**	**Amount**	**Percent**
Crude Oil Production (Mbbl)				
Gulf Coast	**1,020**	1,189	(169)	(14)%
West	**162**	123	39	32%
East	**19**	20	(1)	(5)%
Canada	**8**	14	(6)	(43)%
Total Company	**1,209**	1,346	(137)	(10)%
Crude Oil Sales Price ($/Bbl)				
Gulf Coast	**$ 66.71**	$ 42.72	$ 23.99	56%
West	**$ 64.99**	$ 54.21	$ 10.78	20%
East	**$ 63.29**	$ 52.98	$ 10.31	19%
Canada	**$ 65.90**	$ 42.23	$ 23.67	56%
Total Company	**$ 66.42**	$ 43.92	$ 22.50	51%
Crude Oil Revenue (in thousands)				
Gulf Coast	**$ 67,967**	$ 50,804	$ 17,163	34%
West	**10,545**	6,651	3,894	59%
East	**1,220**	1,074	146	14%
Canada	**551**	586	(35)	(6)%
Total Company	**$ 80,283**	$ 59,115	$ 21,168	36%
Price Variance Impact on Crude Oil Revenue				
(in thousands)				
Gulf Coast	**$ 24,397**			
West	**1,804**			
East	**167**			
Canada	**198**			
Total Company	**$ 26,566**			
Volume Variance Impact on Crude Oil Revenue				
(in thousands)				
Gulf Coast	**$ (7,234)**			
West	**2,090**			
East	**(21)**			
Canada	**(233)**			
Total Company	**$ (5,398)**			

The increase in the realized crude oil price combined with the decline in production resulted in a net revenue increase of $21.2 million, excluding the unrealized impact of derivative instruments. The decrease in oil production is primarily the result of decreased Gulf Coast production from the continued natural decline of the CL&F lease in south Louisiana, which was sold in the third quarter of 2006. For the nine months ended September 30, 2006, crude oil and condensate volumes from the properties sold in the third quarter disposition were 634 Mbbl and crude oil and condensate revenues from those properties were approximately $42.8 million.

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Impact of Derivative Instruments on Operating Revenues

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

	Nine Months Ended September 30,			
	2006		2005	
	Realized	Unrealized	Realized	Unrealized
	(In thousands)			
Operating Revenues - Increase/(Decrease) to Revenue				
Cash Flow Hedges				
Natural Gas Production	**$ 17,166**	$	$ (40,211)	$ (186)
Crude Oil			(1,552)	(103)
Total Cash Flow Hedges	**17,166**		(41,763)	(289)
Other Derivative Financial Instruments				
Crude Oil			(10,470)	(1,762)
Total Other Derivative Financial Instruments			(10,470)	(1,762)
	$ 17,166	$	$ (52,233)	$ (2,051)

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.

Other Operating Revenues

Other operating revenues increased by $3.6 million between the first nine months of 2006 and the first nine months of 2005 primarily due to an increase in net profits interest that originated in 2006 as well as a decrease in our payout liability associated with a favorable legal ruling in the first quarter of 2006. This variance also results, to a lesser extent, from changes in our wellhead gas imbalances over the previous year period.

Operating Expenses

Total costs and expenses from operations increased $47.0 million in the first nine months of 2006 compared to the same period of 2005. The primary reasons for this fluctuation are as follows:

Depreciation, Depletion and Amortization increased by $17.5 million in the first nine months of 2006. This is primarily due to increased production for the first nine months of 2006, an increase in finding costs and an increase in the DD&A rate associated with one field in East Texas as well as the commencement of offshore production in late 2005.

Direct Operations expense increased by $12.3 million over the first nine months of 2005. This is primarily the result of an increase over the prior year period in outside operated properties expense, compressor expense, workovers, treating and disposal costs, as well as expenses for incentive compensation and personnel related charges. The increase in outside operated properties expense resulted from increases in the Gulf Coast region, largely from accruals related to repairs on a plant damaged by the hurricanes that occurred in 2005 and also, to a lesser extent, in the West region.

General and Administrative expense increased by $10.7 million in the first nine months of 2006. This increase is primarily due to increased stock compensation costs of $5.0 million. During the first nine months of 2006, performance share and restricted stock amortization expense increased by $2.6 million and $1.5 million, respectively, primarily due to new grants issued in 2006 and changes in the accounting for the value of performance shares. For the first nine months of the year, expense related to SARs, which were granted for the first time in 2006, and stock options, which are being expensed in 2006 due to the adoption of SFAS No. 123(R), increased by $0.9 million in total. In addition, there is an increase in litigation expense and incentive compensation related to employee bonuses over the first nine months of the prior year.

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Taxes Other Than Income increased by $7.4 million compared to the first nine months of 2005, primarily due to increased production taxes as a result of increased commodity prices as well as an increase in ad valorem taxes and, to a lesser extent, franchise taxes.

Brokered Natural Gas Cost increased by $6.4 million from the first nine months of 2005 to the first nine months of 2006. See the preceding table labeled Brokered Natural Gas Revenue and Cost for further analysis.

Exploration expense decreased by $7.4 million in the first nine months of 2006, primarily as a result of decreased dry hole expense of $9.1 million, mainly as a result of a decrease in the Gulf Coast attributable to a more successful drilling program in the first nine months of 2006 compared to the first nine months of 2005 and, to a lesser extent, better success in Canada, partially offset by an increase in dry hole expense in the West region. Partially offsetting this overall decrease in dry hole expense is an increase in employee expenses for salaries and benefits of approximately $0.8 million for employees in this division as well as increased delay rental expenses of $0.4 million.

Interest Expense, Net

Interest expense, net increased $4.0 million in the first nine months of 2006 due to higher credit facility borrowings as well as an increasing interest rate environment. Weighted average borrowings based on daily balances were approximately $81 million during the first nine months of 2006 compared to $49 million during the first nine months of 2005.

Income Tax Expense

Income tax expense increased by $112.3 million due to a comparable increase in our pre-tax income, primarily as a result of the gain on the sale of assets recorded in the third quarter of 2006. The effective tax rate for the first nine months of 2006 and 2005 is 36.4% and 37.2%, respectively. The decrease in the effective tax rate is primarily due to the recognition of a change in the Texas state income tax rate due to a change in the tax law in May 2006. In addition, there was a change in the overall blended state income tax rate due to sale in the third quarter of 2006 of certain south Louisiana and offshore properties.

Recently Issued Accounting Pronouncements

In February 2006, the Financial Accounting Standards Board (FASB) issued SFAS No. 155, Accounting for Certain Hybrid Financial Instruments-an amendment of FASB Statements No. 133 and 140. SFAS No. 155 amends SFAS No. 133, Accounting for Derivative Instruments and Hedging Activities and SFAS No. 140, Accounting for Transfers and Servicing of Financial Assets and Extinguishments of Liabilities, and also resolves issues addressed in SFAS No. 133 Implementation Issue No. D1, Application of Statement 133 to Beneficial Interests in Securitized Financial Assets. SFAS No. 155 was issued to eliminate the exemption from applying SFAS No. 133 to interests in securitized financial assets so that similar instruments are accounted for in a similar fashion, regardless of the instrument s form. We do not believe that our financial position, results of operations or cash flows will be impacted by SFAS No. 155 as we do not currently hold any hybrid financial instruments.

In July 2006, the FASB issued FASB Interpretation (FIN) No. 48, Accounting for Uncertainty in Income Taxes-an interpretation of FASB Statement No. 109. This Interpretation provides guidance for recognizing and measuring uncertain tax positions, as defined in SFAS No. 109, Accounting for Income Taxes. FIN No. 48 prescribes a two-step process for accounting for income tax uncertainties. First, a threshold condition of more likely than not should be met to determine whether any of the benefit of the uncertain tax position should be recognized in the financial statements. If the recognition threshold is met, FIN 48 provides additional guidance on measuring the amount of the uncertain tax position. Guidance is also provided regarding derecognition, classification, interest and penalties, interim period accounting, transition and disclosure of these uncertain tax positions. FIN 48 is effective for fiscal years beginning after December 15, 2006. We are currently evaluating the impact, if any, that this Interpretation may have on our financial position, results of operations and cash flows.

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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 U.S generally accepted accounting principles (GAAP) 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. No new fair value measurements are prescribed, and SFAS No. 157 is intended to codify the several definitions of fair value included in various accounting standards. However, the application of this Statement may change current practices for certain companies. SFAS No. 157 is effective for fiscal years beginning after November 15, 2007. We are currently evaluating what impact SFAS No. 157 may have on our financial position, results of operations or cash flows.

In September 2006, the FASB issued SFAS No. 158, Employers Accounting for Defined Benefit Pension and Other Postretirement Plans, an amendment of FASB Statements No. 87, 88, 106, and 132(R). SFAS No. 158 requires recognition of the funded status of a benefit plan in the balance sheet and the recognition through other comprehensive income of gains, losses, prior service costs and credits, net of tax, arising during the period but not included as a component of periodic benefit cost. In addition, the measurement date of plan assets and obligations must be as of a Company s balance sheet date. Additional disclosures in the notes to the financial statements will also be required and guidance is prescribed regarding the selection of discount rates to be used in measuring the benefit obligation. For public companies, the effective date of SFAS No. 158 is as of the end of the fiscal year ending after December 15, 2006. The effective date of the new measurement date provision is for fiscal years ending after December 15, 2008; however, our measurement date is currently its balance sheet date, so no change will be required. We plan to adopt this standard using the prospective transition method of adoption effective with our Annual Report on Form 10-K for the year ended December 31, 2006. The anticipated incremental effect of SFAS No. 158 is to increase our total liabilities and total assets by $18.7 million and $7.1 million, respectively, and to decrease total stockholders equity by $11.6 million based on actuarial reports as of September 30, 2006.

In September 2006, the SEC Staff issued Staff Accounting Bulletin (SAB) No. 108, Considering the Effects of Prior Year Misstatements when Quantifying Misstatements in Current Year Financial Statements, in an effort to address diversity in the accounting practice of quantifying misstatements and the potential for improper amounts on the balance sheet. Prior to the issuance of SAB No. 108, the two methods used for quantifying the effects of financial statement errors were the roll-over and iron curtain methods. Under the roll-over method, the primary focus is the income statement, including the reversing effect of prior year misstatements. The criticism of this method is that misstatements can accumulate on the balance sheet. On the other hand, the iron curtain method focuses on the effect of correcting the ending balance sheet, with less importance on the reversing effects of prior year errors in the income statement. SAB No. 108 establishes a dual approach which requires the quantification of the effect of financial statement errors on each financial statement, as well as related disclosures. Public companies are required to record the cumulative effect of initially adopting the dual approach method in the first year ending after November 16, 2006 by recording any necessary corrections to asset and liability balances with an offsetting adjustment to the opening balance of retained earnings. The use of this cumulative effect transition method also requires detailed disclosures of the nature and amount of each error being corrected and how and when they arose. We are currently evaluating the impact that SAB No. 108 may have on our financial position, results of operations and cash flows.

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.

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ITEM 3. Quantitative and Qualitative Disclosures about Market Risk

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 and Note 7 of the Notes to the Condensed Consolidated Financial Statements for a more detailed discussion of our hedging arrangements.

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 2006, natural gas price collars covered 20,328 Mmcf, or 34%, of our 2006 gas production, with a weighted average floor of $8.25 per Mcf and a weighted average ceiling of $12.74 per Mcf.

At September 30, 2006, we had open natural gas price collar contracts covering our 2006 and 2007 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, 2006			
Fourth Quarter 2006	6,851	$12.74 / $8.25	
Three Months Ended December 31, 2006	**6,851**	**$12.74 / $8.25**	**$ 16,670**
First Quarter 2007	8,444	$12.45 / $9.09	
Second Quarter 2007	8,538	12.45 / 9.09	
Third Quarter 2007	8,632	12.45 / 9.09	
Fourth Quarter 2007	8,632	12.45 / 9.09	
Full Year 2007	**34,246**	**$12.45 /$9.09**	**$ 51,257**

During the first nine months of 2006, crude oil price collars covered 273 Mbbls, or 23%, of our 2006 oil production, with a weighted average floor of $50.00 per Bbl and a weighted average ceiling of $76.00 per Bbl.

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At September 30, 2006, we had open crude oil price collar contracts covering our 2006 and 2007 production as follows:

Contract Period	Volume in Mbbl	Crude Oil Price Collar Weighted Average Ceiling /Floor *(per Bbl)*	Net Unrealized (Loss) / Gain *(In thousands)*
As of September 30, 2006			
Fourth Quarter 2006	92	$76.00 / $50.00	
Three Months Ended December 31, 2006	**92**	**$76.00 / $50.00**	**$ (16)**
First Quarter 2007	90	$80.00 / $60.00	
Second Quarter 2007	91	80.00 / 60.00	
Third Quarter 2007	92	80.00 / 60.00	
Fourth Quarter 2007	92	80.00 / 60.00	
Full Year 2007	**365**	**$80.00 / $60.00**	**$ 212**

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

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

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 Rule 13a-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 most recent fiscal quarter that have materially affected, or are reasonably likely to materially affect, the Company s internal control over financial reporting.

PART II. OTHER INFORMATION

ITEM 1. Legal Proceedings

The information set forth under the captions West Virginia Royalty Litigation, Texas Title Litigation and Raymondville Area in Note 6 of the Notes to the Condensed Consolidated Financial Statements in Item 1 of Part I of this Quarterly Report on Form 10-Q is incorporated by reference in response to this item.

ITEM 1A. Risk Factors

For additional information about the risk factors facing the Company, see Item 1A of Part I of the Company s Annual Report on Form 10-K for the year ended December 31, 2005.

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

Issuer Purchases of Equity Securities

Period	Total Number of Shares Purchased	Average Price Paid per Share	Total Number of Shares Purchased as Part of Publicly Announced Plans or Programs	Maximum Number of Shares that May Yet Be Purchased Under the Plans or Programs
July 2006		$		819,950
August 2006		$		819,950
September 2006	422,300	$ 45.71	422,300	397,650
Total	422,300	$ 45.71		

In August 1998, the Company announced that its Board of Directors authorized the repurchase of two million shares of the Company s common stock in the open market or in negotiated transactions. As a result of the 3-for-2 stock split effected in March 2005, this figure was adjusted to three million shares. All purchases executed to date have been through open market transactions. There is no expiration date associated with the authorization to repurchase securities of the Company.

On October 26, 2006, the Company announced that its Board of Directors increased the number of shares of common stock authorized for repurchase by an additional two million shares.

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ITEM 6. Exhibits

* 10.1	Purchase and Sale Agreement dated August 25, 2006 between Cabot Oil & Gas Corporation, a Delaware corporation, Cody Energy LLC, a Colorado limited liability company, and Phoenix Exploration Company LP, a Delaware limited partnership (incorporated by reference to Exhibit 99.1 of the Company s Current Report on Form 8-K dated September 29, 2006).
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

* Incorporated by reference as indicated

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SIGNATURES

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

	CABOT OIL & GAS CORPORATION (Registrant)
October 27, 2006	By: /s/ Dan O. Dinges Dan O. Dinges Chairman, President and Chief Executive Officer (Principal Executive Officer)
October 27, 2006	By: /s/ Scott C. Schroeder Scott C. Schroeder Vice President and Chief Financial Officer (Principal Financial Officer)
October 27, 2006	By: /s/ Henry C. Smyth Henry C. Smyth Vice President, Controller and Treasurer (Principal Accounting Officer)