

CABOT OIL & GAS CORP
Form 10-Q
July 30, 2009
Table of Contents

UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
WASHINGTON, D.C. 20549
FORM 10-Q

QUARTERLY REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934.
For the quarterly period ended June 30, 2009

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

CABOT OIL & GAS CORPORATION

(Exact name of registrant as specified in its charter)

DELAWARE
(State or other jurisdiction of

04-3072771
(I.R.S. Employer

incorporation or organization)

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

No

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

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

Yes

No

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

Large accelerated filer

Accelerated filer

Non-accelerated filer

Smaller reporting company

(Do not check if a smaller reporting company)

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

Yes

No

As of July 24, 2009, there were 103,644,436 shares of Common Stock, Par Value \$.10 Per Share, outstanding.

Table of Contents

CABOT OIL & GAS CORPORATION

INDEX TO FINANCIAL STATEMENTS

	Page
<u>Part I. Financial Information</u>	
<u>Item 1. Financial Statements</u>	
<u>Condensed Consolidated Statement of Operations for the Three Months and Six Months Ended June 30, 2009 and 2008</u>	3
<u>Condensed Consolidated Balance Sheet at June 30, 2009 and December 31, 2008</u>	4
<u>Condensed Consolidated Statement of Cash Flows for the Six Months Ended June 30, 2009 and 2008</u>	5
<u>Notes to the Condensed Consolidated Financial Statements</u>	6
<u>Report of Independent Registered Public Accounting Firm on Review of Interim Financial Information</u>	23
<u>Item 2. Management's Discussion and Analysis of Financial Condition and Results of Operations</u>	24
<u>Item 3. Quantitative and Qualitative Disclosures about Market Risk</u>	39
<u>Item 4. Controls and Procedures</u>	41
<u>Part II. Other Information</u>	
<u>Item 1A. Risk Factors</u>	41
<u>Item 2. Unregistered Sales of Equity Securities and Use of Proceeds</u>	41
<u>Item 4. Submission of Matters to a Vote of Security Holders</u>	42
<u>Item 6. Exhibits</u>	43
<u>Signatures</u>	44

Table of Contents**PART I. FINANCIAL INFORMATION****ITEM 1. Financial Statements****CABOT OIL & GAS CORPORATION****CONDENSED CONSOLIDATED STATEMENT OF OPERATIONS (Unaudited)**

	Three Months Ended June 30,		Six Months Ended June 30,	
	2009	2008	2009	2008
<i>(In thousands, except per share amounts)</i>				
OPERATING REVENUES				
Natural Gas Production	\$ 176,213	\$ 202,689	\$ 360,735	\$ 369,248
Brokered Natural Gas	11,704	27,188	45,085	62,808
Crude Oil and Condensate	16,210	18,600	30,452	35,087
Other	697	377	2,491	1,362
	204,824	248,854	438,763	468,505
OPERATING EXPENSES				
Brokered Natural Gas Cost	10,684	24,140	40,433	54,430
Direct Operations Field and Pipeline	23,073	22,636	48,552	40,127
Exploration	10,397	7,290	16,863	12,351
Depreciation, Depletion and Amortization	55,108	42,482	110,893	83,998
Impairment of Unproved Properties	6,730	5,919	16,037	10,670
General and Administrative	17,117	33,477	34,182	61,050
Taxes Other Than Income	10,914	19,225	23,812	36,122
	134,023	155,169	290,772	298,748
Gain / (Loss) on Sale of Assets	(16,562)	401	(3,855)	401
INCOME FROM OPERATIONS	54,239	94,086	144,136	170,158
Interest Expense and Other	15,046	6,207	29,272	12,198
Income Before Income Taxes	39,193	87,879	114,864	157,960
Income Tax Expense	13,691	33,254	41,782	57,360
NET INCOME	\$ 25,502	\$ 54,625	\$ 73,082	\$ 100,600
Basic Earnings Per Share	\$ 0.25	\$ 0.55	\$ 0.71	\$ 1.03
Diluted Earnings Per Share	\$ 0.24	\$ 0.55	\$ 0.70	\$ 1.02
Weighted-Average Common Shares Outstanding	103,640	98,467	103,581	98,092
Diluted Common Shares (Note 5)	104,815	99,481	104,312	98,964

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

Table of Contents**CABOT OIL & GAS CORPORATION****CONDENSED CONSOLIDATED BALANCE SHEET (Unaudited)**

<i>(In thousands, except share amounts)</i>	June 30, 2009	December 31, 2008
ASSETS		
Current Assets		
Cash and Cash Equivalents	\$ 29,848	\$ 28,101
Accounts Receivable, Net (Note 3)	54,521	109,613
Inventories (Note 3)	29,514	45,677
Current Derivative Contracts (Note 7)	244,374	264,660
Other Current Assets (Note 3)	12,565	12,500
Total Current Assets	370,822	460,551
Properties and Equipment, Net (Successful Efforts Method) (Note 2)	3,154,753	3,135,828
Long-Term Derivative Contracts (Note 7)	53,014	90,542
Investment in Equity Securities (Note 2)	20,636	
Other Assets (Note 3)	24,459	14,743
	\$ 3,623,684	\$ 3,701,664
LIABILITIES AND STOCKHOLDERS EQUITY		
Current Liabilities		
Accounts Payable (Note 3)	\$ 127,392	\$ 222,985
Current Portion of Long-Term Debt (Note 4)	20,000	35,857
Deferred Income Taxes	56,416	63,985
Income Taxes Payable	8,976	5,535
Accrued Liabilities (Note 3)	52,343	50,551
Total Current Liabilities	265,127	378,913
Long-Term Liability for Pension and Postretirement Benefits (Note 9)	48,077	54,714
Long-Term Debt (Note 4)	795,000	831,143
Deferred Income Taxes	628,234	599,106
Other Liabilities (Note 3)	50,774	47,226
Total Liabilities	1,787,212	1,911,102
Commitments and Contingencies (Note 6)		
Stockholders Equity		
Common Stock:		
Authorized 240,000,000 Shares of \$0.10 Par Value in 2009 and 120,000,000 Shares of \$0.10 Par Value in 2008		
Issued 103,846,636 Shares and 103,561,268 Shares in 2009 and 2008, respectively	10,385	10,356
Additional Paid-in Capital	682,733	675,568
Retained Earnings	988,430	921,561
Accumulated Other Comprehensive Income (Note 8)	158,273	186,426
Less Treasury Stock, at Cost:		
202,200 Shares in 2009 and 2008, respectively	(3,349)	(3,349)
Total Stockholders Equity	1,836,472	1,790,562
	\$ 3,623,684	\$ 3,701,664

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

Table of Contents**CABOT OIL & GAS CORPORATION****CONDENSED CONSOLIDATED STATEMENT OF CASH FLOWS (Unaudited)**

<i>(In thousands)</i>	Six Months Ended June 30,	
	2009	2008
CASH FLOWS FROM OPERATING ACTIVITIES		
Net Income	\$ 73,082	\$ 100,600
Adjustments to Reconcile Net Income to Cash Provided by Operating Activities:		
Depreciation, Depletion and Amortization	110,893	83,998
Impairment of Unproved Properties	16,037	10,670
Deferred Income Tax Expense	38,252	55,515
(Gain) / Loss on Sale of Assets	3,855	(401)
Exploration Expense	16,863	12,351
Unrealized (Gain) / Loss on Derivatives	(815)	2,909
Stock-Based Compensation Expense and Other	13,513	19,830
Changes in Assets and Liabilities:		
Accounts Receivable, Net	55,092	(54,319)
Inventories	16,163	7,651
Other Current Assets	(65)	10,689
Other Assets	5	5,697
Accounts Payable and Accrued Liabilities	(41,894)	20,373
Income Taxes Payable	3,441	(888)
Other Liabilities	(4,037)	1,736
Net Cash Provided by Operating Activities	300,385	276,411
CASH FLOWS FROM INVESTING ACTIVITIES		
Capital Expenditures	(292,741)	(312,445)
Acquisitions	(229)	(60,166)
Proceeds from Sale of Assets	79,667	1,150
Exploration Expense	(16,863)	(12,351)
Net Cash Used in Investing Activities	(230,166)	(383,812)
CASH FLOWS FROM FINANCING ACTIVITIES		
Borrowings from Debt	70,000	180,000
Repayments of Debt	(122,000)	(265,000)
Net Proceeds from Sale of Common Stock	150	316,107
Dividends Paid	(6,213)	(5,873)
Capitalized Debt Issuance Costs	(10,409)	
Net Cash (Used in) / Provided by Financing Activities	(68,472)	225,234
Net Increase in Cash and Cash Equivalents	1,747	117,833
Cash and Cash Equivalents, Beginning of Period	28,101	18,498
Cash and Cash Equivalents, End of Period	\$ 29,848	\$ 136,331

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

Table of Contents

CABOT OIL & GAS CORPORATION

NOTES TO THE CONDENSED CONSOLIDATED FINANCIAL STATEMENTS (Unaudited)

1. FINANCIAL STATEMENT PRESENTATION

During interim periods, Cabot Oil & Gas Corporation (the Company) follows the same accounting policies used in its 2008 Annual Report to Stockholders and its Annual Report on Form 10-K for the year ended December 31, 2008 (Form 10-K) filed with the Securities and Exchange Commission (SEC). The interim financial statements should be read in conjunction with the notes to the financial statements and information presented in the Form 10-K. In management's opinion, the accompanying interim condensed consolidated financial statements contain all material adjustments, consisting only of normal recurring adjustments, necessary for a fair statement. The results for any interim period are not necessarily indicative of the expected results for the entire year. Subsequent events have been evaluated through July 30, 2009, which is also the date that the financial statements were issued.

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

Recently Adopted Accounting Standards

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

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

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

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

Table of Contents

In April 2009, the FASB issued FSP No. FAS 107-1 and Accounting Principles Bulletin (APB) No. 28-1, *Interim Disclosures about Fair Value of Financial Instruments*, to require disclosures about fair value of financial instruments for publicly traded companies for both interim and annual periods. Historically, these disclosures were only required annually. The interim disclosures are intended to provide financial statement users with more timely and transparent information about the effects of current market conditions on an entity's financial instruments that are not otherwise reported at fair value. FSP No. FAS 107-1 became effective for interim reporting periods ending after June 15, 2009, and the Company has provided interim disclosures regarding the fair value of debt instruments in Note 4 of the Notes to the Condensed Consolidated Financial Statements. Comparative disclosures are only required for periods ending after the initial adoption. FSP No. FAS 107-1 did not have a material impact on the Company's financial position, results of operations or cash flows.

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

In June 2009, the FASB issued SFAS No. 165, *Subsequent Events*, which requires entities to disclose the date through which they have evaluated subsequent events and whether the date corresponds with the release of their financial statements. In addition, a new concept of financial statements being available to be issued was introduced. SFAS No. 165 is effective for interim and annual periods ending after June 15, 2009. SFAS No. 165 did not have any impact on the Company's financial position, results of operations or cash flows.

Recently Issued Accounting Pronouncements

In July 2009, the FASB issued SFAS No. 168, *The FASB Accounting Standards Codification and the Hierarchy of Generally Accepted Accounting Principles* as the sole source of authoritative non-governmental U.S. generally accepted accounting principles (GAAP). The Codification is not intended to change U.S. GAAP; however, references to various accounting pronouncements and literature will differ from what is currently being used in practice. As of July 1, 2009, the FASB no longer issues Statements, Interpretations, Staff Positions or EITF Abstracts. All guidance in the Codification has an equal level of authority. SFAS No. 168 will be effective for financial statements that cover interim and annual periods ending after September 15, 2009. Once effective, it will supersede all accounting standards in U.S. GAAP, aside from those issued by the SEC. There will be no impact on the Company's financial position, results of operations or cash flows as a result of the Codification.

In June 2009, the FASB issued SFAS No. 166, *Accounting for Transfers of Financial Assets*. SFAS No. 166 revises SFAS No. 140 and will require entities to provide more information about sales of securitized financial assets and similar transactions, particularly if the seller retains some risk to the assets. SFAS No. 166 will be effective at the beginning of the first fiscal year beginning after November 15, 2009. As the Company does not anticipate having any of these types of transactions in the near future, SFAS No. 166 is not expected to have any impact on its financial position, results of operations or cash flows.

In December 2008, the SEC issued Release No. 33-8995, *Modernization of Oil and Gas Reporting*, which amends the oil and gas disclosures for oil and gas producers contained in Regulations S-K and S-X, as well as adding a section to Regulation S-K (Subpart 1200) to codify the revised disclosure requirements in Securities Act Industry Guide 2, which is being phased out. The goal of Release No. 33-8995 is to provide investors with a more meaningful and comprehensive understanding of oil and gas reserves. Energy companies affected by Release No. 33-8995 will be required to price proved oil and gas reserves using the unweighted arithmetic average of the price

Table of Contents

on the first day of each month within the 12-month period prior to the end of the reporting period, unless prices are defined by contractual arrangements, excluding escalations based on future conditions. SEC Release No. 33-8995 is effective beginning January 1, 2010. The Company is currently evaluating what impact Release No. 33-8995 may have on its financial position, results of operations or cash flows.

2. PROPERTIES AND EQUIPMENT, NET

Properties and equipment, net are comprised of the following:

<i>(In thousands)</i>	June 30, 2009	December 31, 2008
Unproved Oil and Gas Properties	\$ 298,714	\$ 315,782
Proved Oil and Gas Properties	3,936,345	3,813,014
Gathering and Pipeline Systems	269,868	274,192
Land, Building and Other Equipment	70,212	68,606
	4,575,139	4,471,594
Accumulated Depreciation, Depletion and Amortization	(1,420,386)	(1,335,766)
	\$ 3,154,753	\$ 3,135,828

At June 30, 2009, the Company did not have any projects that had exploratory well costs that were capitalized for a period of greater than one year after drilling.

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

The Company recognized a \$3.9 million aggregate loss on sale of assets in the first half of 2009. During the quarter ended June 30, 2009, the Company recorded a \$10.5 million (net of taxes of \$6.1 million) loss on sale of assets, primarily due to the sale of the Canadian properties described above. During the first quarter of 2009, the Company recognized a \$12.7 million gain on sale of assets primarily related to the sale of Thornwood properties in the East region. Cash proceeds of \$11.4 million were received from the sale of the Thornwood properties.

Table of Contents**3. ADDITIONAL BALANCE SHEET INFORMATION**

Certain balance sheet amounts are comprised of the following:

<i>(In thousands)</i>	June 30, 2009	December 31, 2008
ACCOUNTS RECEIVABLE, NET		
Trade Accounts	\$ 47,957	\$ 94,164
Joint Interest Accounts	8,598	16,454
Current Income Tax Receivable		526
Other Accounts	1,779	1,987
	58,334	113,131
Allowance for Doubtful Accounts	(3,813)	(3,518)
	\$ 54,521	\$ 109,613
INVENTORIES		
Natural Gas in Storage	\$ 10,865	\$ 27,478
Tubular Goods and Well Equipment	18,200	16,439
Pipeline Imbalances	449	1,760
	\$ 29,514	\$ 45,677
OTHER CURRENT ASSETS		
Drilling Advances	\$ 2,774	\$ 4,869
Prepaid Balances	9,651	7,631
Other	140	
	\$ 12,565	\$ 12,500
OTHER ASSETS		
Rabbi Trust Deferred Compensation Plan	\$ 9,440	\$ 8,651
Deferred Charges for Credit Agreements	13,779	4,847
Other Accounts	1,240	1,245
	\$ 24,459	\$ 14,743
ACCOUNTS PAYABLE		
Trade Accounts	\$ 10,744	\$ 44,088
Natural Gas Purchases	6,233	5,346
Royalty and Other Owners	31,900	42,349
Capital Costs	63,123	117,029
Taxes Other Than Income	3,150	5,617
Drilling Advances	1,098	1,289
Wellhead Gas Imbalances	4,090	3,354
Other Accounts	7,054	3,913
	\$ 127,392	\$ 222,985
ACCRUED LIABILITIES		
Employee Benefits	\$ 5,849	\$ 10,807

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Current Liability for Pension Benefits	245	245
Current Liability for Postretirement Benefits	642	642
Taxes Other Than Income	23,581	16,582
Interest Payable	19,863	20,684
Other Accounts	2,163	1,591
	\$ 52,343	\$ 50,551
OTHER LIABILITIES		
Rabbi Trust Deferred Compensation Plan	\$ 16,510	\$ 14,531
Accrued Plugging and Abandonment Liability	28,807	27,978
Other Accounts	5,457	4,717
	\$ 50,774	\$ 47,226

Table of Contents**4. LONG-TERM DEBT**

The Company's debt consisted of the following:

<i>(In thousands)</i>	June 30, 2009	December 31, 2008
Long-Term Debt		
7.19% Notes	\$ 20,000	\$ 20,000
7.33% Weighted-Average Fixed Rate Notes	170,000	170,000
6.51% Weighted-Average Fixed Rate Notes	425,000	425,000
9.78% Notes	67,000	67,000
Credit Facility	133,000	185,000
Current Maturities		
7.19% Notes	(20,000)	(20,000)
Credit Facility		(15,857)
Total Current Maturities	(20,000)	(35,857)
Long-Term Debt, excluding Current Maturities	\$ 795,000	\$ 831,143

In April 2009, the Company entered into a new revolving credit facility and terminated its prior credit facility. The credit facility provides for an available credit line of \$500 million and contains an accordion feature allowing the Company to increase the available credit line to \$600 million, if any one or more of the existing banks or new banks agree to provide such increased commitment amount. The term of the facility expires in April 2012. In conjunction with entering into the new credit facility, the Company incurred \$10.4 million of debt issuance costs which were capitalized and will be amortized over term of the facility.

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

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

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

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

- (a) Maintenance of a minimum annual coverage ratio of operating cash flow to interest expense for the trailing four quarters of 2.8 to 1.0.
- (b) Maintenance of an asset coverage ratio of the present value of proved reserves plus working capital to debt of 1.5 to 1.0.

Table of Contents

(c) Maintenance of a current ratio, as defined in the agreement, of 1.0 to 1.0.

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

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

At June 30, 2009, the Company had \$133 million of borrowings outstanding under its revolving credit facility at a weighted-average interest rate of 3.9%.

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

5. EARNINGS PER COMMON SHARE

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

Basic EPS is computed by dividing net income (the numerator) by the weighted-average number of common shares outstanding for the period (the denominator). Diluted EPS is similarly calculated except that the denominator is increased using the treasury stock method to reflect the potential dilution that could occur if stock options and stock awards outstanding at the end of the applicable period were exercised for common stock.

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

	Three Months Ended June 30,		Six Months Ended June 30,	
	2009	2008	2009	2008
Weighted-Average Shares Basic	103,639,938	98,467,311	103,580,755	98,091,641
Dilution Effect of Stock Options and Awards at End of Period	1,174,872	1,014,070	731,091	872,358
Weighted-Average Shares Diluted	104,814,810	99,481,381	104,311,846	98,963,999
Weighted-Average Stock Awards and Shares Excluded from Diluted Earnings per Share due to the Anti-Dilutive Effect	220,489		752,204	274,854

Table of Contents

6. COMMITMENTS AND CONTINGENCIES

Contingencies

The Company is a defendant in various legal proceedings arising in the normal course of its business. All known liabilities are accrued based on management's best estimate of the potential loss. While the outcome and impact of such legal proceedings on the Company cannot be predicted with certainty, management believes that the resolution of these proceedings through settlement or adverse judgment will not have a material adverse effect on the Company's condensed consolidated financial position or cash flow. Operating results, however, could be significantly impacted in the reporting periods in which such matters are resolved.

Commitment and Contingency Reserves

When deemed necessary, the Company establishes reserves for certain legal proceedings. The establishment of a reserve involves an estimation process that includes the advice of legal counsel and subjective judgment of management. While management believes these reserves to be adequate, it is reasonably possible that the Company could incur approximately \$0.9 million of additional loss with respect to those matters in which reserves have been established. Future changes in the facts and circumstances could result in the actual liability exceeding the estimated ranges of loss and amounts accrued.

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

Firm Gas Transportation Agreements

The Company has incurred, and will incur over the next several years, demand charges on firm gas transportation agreements. These agreements provide firm transportation capacity rights on pipeline systems in the West and East regions. The remaining terms on these agreements range from less than one year to approximately 20 years and require the Company to pay transportation demand charges regardless of the amount of pipeline capacity utilized by the Company. If the Company does not utilize the capacity, it can release it to others, thus reducing its potential liability. The agreements that the Company previously had in place on pipeline systems in Canada were transferred in April 2009 to the buyer in connection with the sale of our Canadian properties (discussed in Note 2).

As previously disclosed in the Form 10-K, obligations under firm gas transportation agreements in effect at December 31, 2008 were \$94.7 million. As of June 30, 2009, obligations under firm gas transportation agreements were \$90.7 million. For further information on these future obligations, please refer to Note 7 of the Notes to the Consolidated Financial Statements in the Form 10-K.

Drilling Rig Commitments

In the Form 10-K, the Company disclosed that it had total commitments of \$44.3 million on eight drilling rigs in the Gulf Coast that are under contracts with initial terms of greater than one year. The Company entered into a new drilling rig commitment of approximately \$8 million in the first half of 2009. As of June 30, 2009, the total commitment for nine drilling rigs was \$53.8 million. For further information on these future obligations, please refer to Note 7 of the Notes to the Consolidated Financial Statements in the Form 10-K.

7. FINANCIAL INSTRUMENTS

Fair Value Measurements

In February 2008, the FASB issued FSP No. FAS 157-2, Effective Date of FASB Statement No. 157, which granted a one year deferral (to fiscal years beginning after November 15, 2008, and interim periods within those fiscal years) for certain non-financial assets and liabilities measured on a nonrecurring basis to comply with SFAS No. 157. Effective January 1, 2009, the Company applied the provisions of FAS No. 157 covered under FSP No. 157-2 which

Table of Contents

did not have a material impact on the Company's financial statements. In the future, areas that could cause an impact would primarily be limited to asset impairments including long-lived assets, asset retirement obligations and assets acquired and liabilities assumed in a business combination, if any.

SFAS No. 157, Fair Value Measurements, established a formal framework for measuring fair values of assets and liabilities in financial statements that are already required by United States generally accepted accounting principles to be measured at fair value. As defined in SFAS No. 157, fair value is the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date (exit price). The transaction is based on a hypothetical transaction in the principal or most advantageous market considered from the perspective of the market participant that holds the asset or owes the liability.

The Company utilizes market data or assumptions that market participants who are independent, knowledgeable and willing and able to transact would use in pricing the asset or liability, including assumptions about risk and the risks inherent in the inputs to the valuation technique. These inputs can be readily observable, market corroborated or generally unobservable. The Company attempts to utilize valuation techniques that maximize the use of observable inputs and minimize the use of unobservable inputs. The Company is able to classify fair value balances based on the observability of those inputs. SFAS No. 157 establishes a formal fair value hierarchy based on the inputs used to measure fair value. The hierarchy gives the highest priority to level 1 measurements and the lowest priority to level 3 measurements, and accordingly, level 1 measurements should be used whenever possible. For further information regarding the fair value hierarchy and SFAS No. 157, refer to Note 11 of the Notes to the Consolidated Financial Statements in the Form 10-K.

In accordance with SFAS No. 157, the Company has classified its assets and liabilities into these levels depending upon the data relied on to determine the fair values. The fair values of the Company's natural gas and crude oil price collars and swaps are designated as Level 3. The following fair value hierarchy table presents information about the Company's assets and liabilities measured at fair value on a recurring basis as of June 30, 2009:

<i>(In thousands)</i>	Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Balance as of June 30, 2009
Assets				
Rabbi Trust Deferred Compensation Plan	\$ 9,440	\$	\$	\$ 9,440
Derivative Contracts			297,388	297,388
Total Assets	\$ 9,440	\$	\$ 297,388	\$ 306,828
Liabilities				
Rabbi Trust Deferred Compensation Plan	\$ 16,510	\$	\$	\$ 16,510
Derivative Contracts				
Total Liabilities	\$ 16,510	\$	\$	\$ 16,510

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

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

Table of Contents

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

<i>(In thousands)</i>	Three Months Ended June 30,		Six Months Ended June 30,	
	2009	2008	2009	2008
Balance at beginning of period	\$ 405,186 ⁽¹⁾	\$ (85,387) ⁽²⁾	\$ 355,202 ⁽³⁾	\$ 7,272 ⁽⁴⁾
Total Gains or (Losses) (Realized or Unrealized):				
Included in Earnings ⁽⁵⁾	106,802	(28,326)	196,837	(29,348)
Included in Other Comprehensive Income	(107,672)	(194,476)	(58,629)	(287,135)
Purchases, Issuances and Settlements	(106,928)	25,418	(196,022)	26,440
Transfers In and/or Out of Level 3				
Balance at end of period	\$ 297,388	\$ (282,771)	\$ 297,388	\$ (282,771)

(1) Balance was entirely comprised of derivative assets.

(2) Balance was comprised of derivative liabilities of \$85.8 million and derivative assets of \$0.4 million.

(3) Balance was entirely comprised of derivative assets.

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

(5) A loss of \$0.1 million and a gain of \$0.8 million for the three and six months ended June 30, 2009, respectively, was unrealized and included in Natural Gas Production Revenues in the Statement of Operations for the three months and six months ended June 30, 2009. All gains included in earnings for the three and six months ended June 30, 2008 were realized.

The derivative contracts were measured based on quotes from the Company's counterparties. Such quotes have been derived using a Black-Scholes model that considers various inputs including current market and contractual prices for the underlying instruments, quoted forward prices for natural gas and crude oil, volatility factors and interest rates, such as a LIBOR curve for a similar length of time as the derivative contract term. Although the Company utilizes multiple quotes to assess the reasonableness of its values, the Company has not attempted to obtain sufficient corroborating market evidence to support classifying these derivative contracts as Level 2. The Company measured the nonperformance risk of its counterparties by reviewing credit default swap spreads for the various financial institutions in which it has derivative transactions. The resulting reduction to the net receivable derivative contract position was \$1.8 million. In times where the Company has net derivative contract liabilities, the nonperformance risk of the Company is evaluated using a market credit spread provided by the Company's bank.

Fair Market Value of Financial Instruments

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

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The Company uses available market data and valuation methodologies to estimate the fair value of debt. This disclosure is presented in accordance with SFAS No. 107, Disclosures about Fair Value of Financial Instruments as well as SFAS No. 157, Fair Value Measurements and does not impact the Company's financial position, results of operations or cash flows.

Table of Contents

	June 30, 2009		December 31, 2008	
	Carrying Amount	Estimated Fair Value	Carrying Amount	Estimated Fair Value
<i>(In thousands)</i>				
Long-Term Debt	\$ 815,000	\$ 816,698	\$ 867,000	\$ 807,508
Current Maturities	(20,000)	(20,682)	(35,857)	(35,796)
Long-Term Debt, excluding Current Maturities	\$ 795,000	\$ 796,016	\$ 831,143	\$ 771,712

Derivative Instruments and Hedging Activity

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

The Company periodically enters into derivative commodity instruments to hedge its exposure to price fluctuations on natural gas and crude oil production. The Company's credit agreement restricts the ability of the Company to enter into commodity hedges other than to hedge or mitigate risks to which the Company has actual or projected exposure or as permitted under the Company's risk management policies and not subjecting the Company to material speculative risks. All of the Company's derivatives are used for risk management purposes and are not held for trading purposes. As of June 30, 2009, the Company had 26 cash flow hedges open: 14 natural gas price collar arrangements, 10 natural gas price swap arrangements and two crude oil price swap arrangements. During the first half of 2009, the Company entered into six new derivative contracts covering anticipated natural gas production for 2012. These natural gas basis swaps did not qualify for hedge accounting under SFAS No. 133. These natural gas basis swaps mitigate the risk associated with basis differentials that may expand or increase over time, thus reducing the exposure and risk of basis fluctuations.

As of June 30, 2009, the Company had the following outstanding commodity derivatives:

Commodity	Derivative Type	Weighted-Average Contract Price ⁽¹⁾		Volume	Contract Period
Derivatives designated as Hedging Instruments under Statement 133					
Natural Gas	Collar	\$12.39 / \$9.40	per Mcf	23,820	Mmcf 2009
Natural Gas	Swap	\$11.43	per Mcf	19,295	Mmcf 2010
Natural Gas	Swap	\$12.18	per Mcf	8,106	Mmcf 2009
Crude Oil	Swap	\$125.25	per Bbl	184	Mbbl 2009
Crude Oil	Swap	\$125.00	per Bbl	365	Mbbl 2010
Derivatives not qualifying as Hedging Instruments under Statement 133					
Natural Gas	Basis Swap	\$(0.27)	per Mcf	16,123	Mmcf 2012

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

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

Table of Contents

The following schedules reflect the fair values of derivative instruments on the Company's condensed consolidated financial statements as of June 30, 2009:

Effect of derivative instruments on the Condensed Consolidated Balance Sheet

<i>(In thousands)</i>	Asset Derivatives		Liability Derivatives	
	Balance Sheet Location	Fair Value	Balance Sheet Location	Fair Value
Derivatives designated as Hedging Instruments under Statement 133				
Natural Gas Commodity Contracts	Current Derivative Contracts	\$ 223,870		\$
Natural Gas Commodity Contracts	Long-Term Derivative Contracts	43,420		
Crude Oil Commodity Contracts	Current Derivative Contracts	20,504		
Crude Oil Commodity Contracts	Long-Term Derivative Contracts	8,779		
		\$ 296,573		
Derivatives not qualifying as Hedging Instruments under Statement 133				
Natural Gas Commodity Basis Contracts	Long-Term Derivative Contracts	815		
		\$ 297,388		

At June 30, 2009, a \$296.6 million (\$186.3 million, net of tax) unrealized gain was recorded in Accumulated Other Comprehensive Income / (Loss). For the natural gas commodity basis contracts that were not designated as hedging instruments, a \$0.8 million unrealized gain was recorded in the Condensed Consolidated Statement of Operations as a component of Natural Gas Production Revenue for the six months ended June 30, 2009.

Effect of derivative instruments on the Condensed Consolidated Statement of Operations

<i>(In thousands)</i>	Amount of Gain Recognized in OCI on Derivative (Effective Portion)	Location of Gain Reclassified from Accumulated OCI into Income (Effective Portion)	Amount of Gain Reclassified from Accumulated OCI into Income (Effective Portion)	Location of Gain Recognized in Income on Derivative (Ineffective Portion and Amount Excluded from Effectiveness Testing)
	Derivatives designated as Hedging Instruments under Statement 133			
Natural Gas Commodity Contracts	\$ 267,290	Natural Gas Production Revenues	\$ 182,666	N/A
Crude Oil Commodity Contracts	29,283	Crude Oil and Condensate Revenues	13,356	N/A
	\$ 296,573		\$ 196,022	

<i>(In thousands)</i>	Location of Gain Recognized in Income on Derivative	Amount of Gain Recognized in Income on Derivative
Derivatives not qualifying as Hedging Instruments under Statement 133		
Natural Gas Commodity Contracts	Natural Gas Production Revenues	\$ 815

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Based upon estimates at June 30, 2009, the Company would expect to reclassify from Other Comprehensive Income to the Condensed Consolidated Statement of Operations over the next 12 months \$153.5 million in after-tax income associated with its commodity hedges. This reclassification represents the net short-term receivable (after the impact of taxes) associated with open positions currently not reflected in earnings at June 30, 2009 related to anticipated 2009 and 2010 production.

Table of Contents**8. COMPREHENSIVE INCOME / (LOSS)**

Comprehensive Income / (Loss) includes Net Income and certain items recorded directly to Stockholders' Equity and classified as Accumulated Other Comprehensive Income / (Loss). The following tables illustrate the calculation of Comprehensive Income / (Loss) for the three and six month periods ended June 30, 2009 and 2008:

<i>(In thousands)</i>	Three Months Ended June 30,			
	2009			2008
Accumulated Other Comprehensive Income / (Loss) Beginning of Period		\$ 216,684		\$ (60,872)
Net Income	\$ 25,502		\$ 54,625	
Other Comprehensive Income / (Loss), net of taxes:				
Reclassification Adjustment for Settled Contracts, net of taxes of \$40,182 and \$(9,404), respectively		(66,746)		16,014
Changes in Fair Value of Hedge Positions, net of taxes of \$277 and \$81,249, respectively		(467)		(138,645)
Defined Benefit Pension and Postretirement Plans:				
Amortization of Net Obligation at Transition, net of taxes of \$(59) and \$(58), respectively	\$ 99		\$ 100	
Amortization of Prior Service Cost, net of taxes of \$(67) and \$(93), respectively	112		157	
Amortization of Net Loss, net of taxes of \$(358) and \$(172), respectively	606	817	294	551
Foreign Currency Translation Adjustment, net of taxes of \$(4,751) and \$(189), respectively		7,985		350
Total Other Comprehensive Loss	(58,411)	(58,411)	(121,730)	(121,730)
Comprehensive Loss	\$ (32,909)		\$ (67,105)	
Accumulated Other Comprehensive Income / (Loss) End of Period		\$ 158,273		\$ (182,602)

Table of Contents

<i>(In thousands)</i>	Six Months Ended June 30,			
	2009		2008	
Accumulated Other Comprehensive Income / (Loss) Beginning of Period		\$ 186,426		\$ (894)
Net Income	\$ 73,082		\$ 100,600	
Other Comprehensive Income / (Loss), net of taxes:				
Reclassification Adjustment for Settled Contracts, net of taxes of \$73,413 and \$(9,783), respectively		(122,609)		16,657
Changes in Fair Value of Hedge Positions, net of taxes of \$(51,604) and \$116,027, respectively		85,789		(197,548)
Defined Benefit Pension and Postretirement Plans:				
Amortization of Net Obligation at Transition, net of taxes of \$(118) and \$(117), respectively	\$ 198		\$ 199	
Amortization of Prior Service Cost, net of taxes of \$(134) and \$(186), respectively		225		315
Amortization of Net Loss, net of taxes of \$(717) and \$(300), respectively	1,210	1,633	512	1,026
Foreign Currency Translation Adjustment, net of taxes of \$(4,167) and \$1,169, respectively		7,034		(1,843)
Total Other Comprehensive Loss		(28,153)	(28,153)	(181,708) (181,708)
Comprehensive Income / (Loss)	\$ 44,929		\$ (81,108)	
Accumulated Other Comprehensive Income / (Loss) End of Period		\$ 158,273		\$ (182,602)

Changes in the components of Accumulated Other Comprehensive Income / (Loss), net of taxes, for the six months ended June 30, 2009 were as follows:

Accumulated Other Comprehensive Income,

net of taxes <i>(In thousands)</i>	Net Gains on Cash Flow Hedges	Defined Benefit Pension and Postretirement Plans	Foreign Currency Translation Adjustment	Total
Balance at December 31, 2008	\$ 223,068	\$ (29,608)	\$ (7,034)	\$ 186,426
Net change in unrealized gain on cash flow hedges, net of taxes of \$21,809	(36,820)			(36,820)
Net change in defined benefit pension and postretirement plans, net of taxes of \$(969)		1,633		1,633
Change in foreign currency translation adjustment, net of taxes of \$(4,167)			7,034	7,034
Balance at June 30, 2009	\$ 186,248	\$ (27,975)	\$ 7,034	\$ 158,273

Table of Contents**9. PENSION AND OTHER POSTRETIREMENT BENEFITS**

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

<i>(In thousands)</i>	Three Months Ended June 30,		Six Months Ended June 30,	
	2009	2008	2009	2008
Qualified and Non-Qualified Pension Plans				
Current Period Service Cost	\$ 861	\$ 828	\$ 1,722	\$ 1,657
Interest Cost	928	818	1,856	1,636
Expected Return on Plan Assets	(671)	(884)	(1,342)	(1,767)
Amortization of Prior Service Cost	13	13	26	25
Amortization of Net Loss	794	294	1,588	587
Net Periodic Pension Cost	\$ 1,925	\$ 1,069	\$ 3,850	\$ 2,138
Postretirement Benefits Other than Pension Plans				
Current Period Service Cost	\$ 320	\$ 307	\$ 640	\$ 541
Interest Cost	398	382	797	690
Amortization of Prior Service Cost	167	238	333	476
Amortization of Net Loss	169	171	338	224
Amortization of Net Obligation at Transition	158	158	316	316
Total Postretirement Benefit Cost	\$ 1,212	\$ 1,256	\$ 2,424	\$ 2,247

Employer Contributions

The funding levels of the pension and postretirement plans are in compliance with standards set by applicable law or regulation. The Company does not have any required minimum funding obligations for its qualified pension plan in 2009. The Company previously disclosed in its financial statements for the year ended December 31, 2008 that it expected to contribute \$0.3 million to its non-qualified pension plan and \$0.8 million to the postretirement benefit plan during 2009. It is anticipated that these contributions will be made prior to December 31, 2009. In May 2009, the Company made a contribution of \$10 million to its qualified pension plan.

10. STOCK-BASED COMPENSATION

Compensation expense charged against income for stock-based awards (including the supplemental employee incentive plans) during the first half of 2009 and 2008 was \$11.3 million and \$39.3 million, respectively, and is included in General and Administrative Expense in the Condensed Consolidated Statement of Operations. Stock-based compensation expense in the second quarter of 2009 and 2008 was \$6.2 million and \$21.7 million, respectively.

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

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

Table of Contents***Restricted Stock Awards***

During the first half of 2009, the Compensation Committee granted 10,800 restricted stock awards with a weighted-average grant date per share value of \$29.33. The fair value of restricted stock grants is based on the average of the high and low stock price on the grant date. During the first half of 2009, 31,240 restricted stock awards vested with a weighted-average grant date per share value of \$23.80.

Compensation expense recorded for all unvested restricted stock awards for the first six months of 2009 and 2008 was \$0.4 million and \$1.0 million, respectively. Compensation expense recorded for all unvested restricted stock awards for the second quarter of 2009 and 2008 was \$0.2 million and \$0.3 million, respectively. The Company used an annual forfeiture rate ranging from 0% to 7.1% based on approximately ten years of the Company's history for this type of award to various employee groups.

Restricted Stock Units

During the six months ended June 30, 2009, 33,150 restricted stock units were granted to non-employee directors of the Company with a grant date per share value of \$22.63. The fair value of these units is measured at the average of the high and low stock price on grant date and compensation expense is recorded immediately. These units immediately vest and are paid out when the director ceases to be a director of the Company. The compensation cost, which reflects the total fair value of these units, recorded in the first half of 2009 and 2008 was \$0.8 million in each period. There was no expense recorded in the second quarter of either 2009 or 2008.

Stock Appreciation Rights

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

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

	Six Months Ended June 30, 2009
Weighted-Average Value per Stock Appreciation Right Granted During the Period	\$ 9.35
Assumptions	
Stock Price Volatility	50.5%
Risk Free Rate of Return	1.7%
Expected Dividend	0.5%
Expected Term (in years)	4.5

Compensation expense recorded during the first half of 2009 and 2008 for SARs was \$1.3 million and \$1.2 million, respectively. Included in these amounts were \$0.7 million and \$0.5 million in the first half of 2009 and 2008, respectively, related to the immediate expensing of shares granted in 2009 and 2008 to retirement-eligible employees. Compensation expense in the second quarter of 2009 and 2008 was \$0.3 million and \$0.4 million, respectively.

Performance Share Awards

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

Table of Contents

Awards totaling 207,730 performance shares are earned, or not earned, based on the comparative performance of the Company's common stock measured against sixteen other companies in the Company's peer group over a three year performance period. The grant date per share value of the equity portion of this award was \$17.63. Depending on the Company's performance, employees may receive an aggregate of up to 100% of the fair market value of a share of common stock payable in common stock plus up to 100% of the fair market value of a share of common stock payable in cash.

Awards totaling 376,510 performance shares are earned, or not earned, based on the Company's internal performance metrics rather than performance compared to a peer group. The grant date per share value of this award was \$22.63. These awards represent the right to receive up to 100% of the award in shares of common stock. The actual number of shares issued at the end of the performance period will be determined based on the Company's performance against three performance criteria set by the Company's Compensation Committee. An employee will earn one-third of the award granted for each internal performance metric that the Company meets at the end of the performance period. These performance criteria measure the Company's average production, average finding costs and average reserve replacement over three years. Based on the Company's probability assessment at June 30, 2009, it is considered probable that these three criteria will be met.

The third type of performance share award, totaling 201,110 performance shares, with a grant date per share value of \$22.63, has a three-year graded vesting schedule, vesting one-third on each anniversary date following the date of grant, provided that the Company has \$100 million or more of operating cash flow for the year preceding the vesting date. If the Company does not have \$100 million or more of operating cash flow for the year preceding a vesting date, then the portion of the performance shares that would have vested on that date will be forfeited. As of June 30, 2009, it is considered probable that this performance metric will be met for 2009.

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

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

The four primary inputs for the Monte Carlo model are the risk-free rate, volatility of returns, correlation in movement of total shareholder return and the expected dividend. An interpolated risk-free rate was generated from the Federal Reserve website for constant maturity treasuries for two and three year bonds (as of the reporting date) set equal to the remaining duration of the performance period. Volatility was set equal to the annualized daily volatility for the remaining duration of the reporting period ending on the reporting date. Correlation in movement of total shareholder return was determined based on a correlation matrix that was created which identifies total shareholder return correlations for each pair of companies in the peer group, including the Company. The paired returns in the correlation matrix ranged from approximately 49% to approximately 88% for the Company and its peer group. The expected dividend is calculated using the total Company annual dividends expected to be paid (\$0.12 per share) divided by the June 30, 2009 closing price of the Company's stock (\$30.64). Based on these inputs discussed above, a ranking was projected identifying the Company's rank relative to the peer group for each award period.

The following assumptions were used as of June 30, 2009 for the Monte Carlo model to value the liability components of the peer group measured performance share awards. The equity portion of the award was valued on the date of grant using the Monte Carlo model and this portion was not marked to market.

	June 30, 2009
Risk Free Rate of Return	0.4% - 1.4%
Stock Price Volatility	63.6% - 78.1%
Expected Dividend	0.4%

Table of Contents

The Monte Carlo value per share for the liability component for all outstanding market condition performance share awards ranged from \$11.59 to \$14.20 at June 30, 2009. The long-term liability for market condition performance share awards, included in Other Liabilities in the Condensed Consolidated Balance Sheet, at June 30, 2009 and December 31, 2008 was \$1.1 million and \$0.3 million, respectively. The short-term liability, included in Accrued Liabilities in the Condensed Consolidated Balance Sheet, at June 30, 2009 and December 31, 2008, for market condition performance share awards was \$0.9 million and \$2.5 million, respectively.

During the first half of 2009, 332,642 performance shares vested. As discussed in Note 10 of the Notes to the Consolidated Financial Statements in the Form 10-K, the performance period ended on December 31, 2008 for two types of performance shares awarded in 2006. A total of 105,800 shares measured based on the Company's performance against a peer group (valued at \$1.7 million) were awarded in addition to cash of \$1.8 million. A total of 155,800 shares measured based on internal performance metrics of the Company (valued at \$3.8 million) were also awarded. During the first quarter of 2009, 60,740 shares vested (valued at \$2.5 million) which represents one-third of the three-year graded vesting schedule performance share awards granted in 2008 and 2007 with a grant date per share value of \$48.48 and \$35.22, respectively. These awards met the performance criteria that the Company had positive operating income for 2008 and 2007. During the second quarter of 2009, 10,302 performance shares vested as a result of early vesting schedules for certain employees.

As of June 30, 2009, 256,400 shares of the Company's common stock representing vested performance share awards were deferred into the Rabbi Trust Deferred Compensation Plan. For the first half of 2009, an increase to the rabbi trust deferred compensation liability of \$1.2 million was recognized, representing the increase in the closing price of all shares from December 31, 2008 to June 30, 2009. This increase in stock-based compensation expense was included in General and Administrative expense in the Condensed Consolidated Statement of Operations.

Total compensation cost recognized for both the equity and liability components of all performance share awards as well as expense related to the shares deferred into the rabbi trust during the six months ended June 30, 2009 and 2008 was \$8.8 million and \$20.5 million, respectively. Total compensation cost recognized for both the equity and liability components of all performance share awards as well as expense related to the shares deferred into the rabbi trust during the second quarter of 2009 and 2008 was \$5.7 million and \$9.7 million, respectively.

11. INCREASE IN AUTHORIZED SHARES

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

Table of Contents

Report of Independent Registered Public Accounting Firm

To the Board of Directors and Stockholders of

Cabot Oil & Gas Corporation:

We have reviewed the accompanying condensed consolidated balance sheet of Cabot Oil & Gas Corporation and its subsidiaries (the Company) as of June 30, 2009, and the related condensed consolidated statements of operations for the three-month and six-month periods ended June 30, 2009 and 2008 and the condensed consolidated statement of cash flows for the six-month periods ended June 30, 2009 and 2008. These interim financial statements are the responsibility of the Company's management.

We conducted our review in accordance with the standards of the Public Company Accounting Oversight Board (United States). A review of interim financial information consists principally of applying analytical procedures and making inquiries of persons responsible for financial and accounting matters. It is substantially less in scope than an audit conducted in accordance with the standards of the Public Company Accounting Oversight Board (United States), the objective of which is the expression of an opinion regarding the financial statements taken as a whole. Accordingly, we do not express such an opinion.

Based on our review, we are not aware of any material modifications that should be made to the accompanying condensed consolidated interim financial statements for them to be in conformity with accounting principles generally accepted in the United States of America.

We previously audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States) the consolidated balance sheet as of December 31, 2008, and the related consolidated statements of operations, of comprehensive income, of stockholders' equity, and of cash flows for the year then ended (not presented herein), and in our report dated February 27, 2009, which included an explanatory paragraph related to changes in the manner of accounting for fair value measurements and defined pension and postretirement plans, we expressed an unqualified opinion on those consolidated financial statements. In our opinion, the information set forth in the accompanying condensed consolidated balance sheet information as of December 31, 2008, is fairly stated in all material respects in relation to the consolidated balance sheet from which it has been derived.

/s/ PricewaterhouseCoopers LLP

Houston, Texas

July 30, 2009

Table of Contents**ITEM 2. Management's Discussion and Analysis of Financial Condition and Results of Operations**

The following review of operations for the three and six month periods ended June 30, 2009 and 2008 should be read in conjunction with our Condensed Consolidated Financial Statements and the Notes included in this Form 10-Q and with the Consolidated Financial Statements, Notes and Management's Discussion and Analysis included in the Cabot Oil & Gas Annual Report on Form 10-K for the year ended December 31, 2008 (Form 10-K).

Overview

On an equivalent basis, our production level for the six months ended June 30, 2009 increased by 13% compared to the six months ended June 30, 2008. For the six months ended June 30, 2009, we produced 51.2 Bcfe compared to production of 45.4 Bcfe for the six months ended June 30, 2008. Natural gas production was 48.8 Bcf and oil production was 383 Mbbls for the first half of 2009. Natural gas production increased by 13% when compared to the first half of 2008, which had production of 43.1 Bcf. This increase was primarily a result of increased natural gas production in the Gulf Coast region associated with the properties we acquired in east Texas in August 2008, drilling in the County Line field, as well as increased production in the East region associated with the initiation of production in Susquehanna County, Pennsylvania. Partially offsetting these production gains were decreases in production in Canada due to the sale of our Canadian properties in April 2009 and reduced drilling activity as well as natural declines in the West. Oil production increased by one percent, from 379 Mbbls in the first half of 2008 to 383 Mbbls produced in the first half of 2009. This was primarily the result of increases in the Gulf Coast, offset in part by declines in production in all other regions.

Our average realized natural gas price for the first half of 2009 was \$7.38 per Mcf, 14% lower than the \$8.63 per Mcf price realized in the first half of 2008. Our average realized crude oil price for the first half of 2009 was \$79.55 per Bbl, 14% lower than the \$92.58 per Bbl price realized in the first half of 2008. These realized prices include realized gains and losses resulting from commodity derivatives (zero-cost collars or swaps). For information about the impact of these derivatives on realized prices, refer to Results of Operations below. Commodity prices are determined by many factors that are outside of our control. Historically, commodity prices have been volatile, and we expect them to remain volatile. Commodity prices are affected by changes in market supply and demand, which are impacted by overall economic activity, weather, pipeline capacity constraints, inventory storage levels, basis differentials and other factors. As a result, we cannot accurately predict future natural gas, NGL and crude oil prices and, therefore, we cannot determine with any degree of certainty what effect increases or decreases will have on our future revenues, capital program or production volumes.

Operating revenues for the six months ended June 30, 2009 decreased by \$29.7 million, or six percent, from the six months ended June 30, 2008 as the lower commodity prices noted above more than offset the higher equivalent production. Natural gas production revenues decreased by \$8.5 million, or two percent, for the six months ended June 30, 2009 as compared to the six months ended June 30, 2008 due to the decrease in realized natural gas prices, partially offset by the increase in natural gas production, as discussed above. Crude oil and condensate revenues decreased by \$4.6 million, or 13%, for the first six months of 2009 as compared to the first six months of 2008 due to a decrease in realized crude oil prices (primarily due to a decline in realized crude oil prices in the West), partially offset by the increase in crude oil production in the Gulf Coast. Brokered natural gas revenues decreased by \$17.7 million, or 28%, due to a decrease in sales price that outpaced the decrease in purchase price, partially offset by an increase in brokered volumes.

In addition to production volumes and commodity prices, finding and developing sufficient amounts of crude oil and natural gas reserves at economical costs are critical to our long-term success. For 2009, we expect to spend approximately \$500 million in capital and exploration expenditures. We believe our cash on hand and operating cash flow in 2009 will be sufficient to fund our budgeted capital and exploration spending. Any additional needs will be funded by borrowings from our credit facility. We will continue to assess the natural gas and crude oil price environment and our liquidity position and may increase or decrease the capital and exploration expenditures accordingly. For the six months ended June 30, 2009, approximately \$260.6 million has been invested in our exploration and development efforts.

During the first six months of 2009, we drilled 82 gross wells (77 development, two exploratory and three extension wells) with a success rate of 98% compared to 201 gross wells (196 development, three exploratory and two extension wells) with a success rate of 99% for the comparable period of the prior year. For the full year of 2009, we plan to drill approximately 149 gross wells.

Table of Contents

We remain focused on our strategies of pursuing lower risk drilling opportunities that provide more predictable results on our accumulated acreage position. Additionally, we intend to maintain spending discipline and manage our balance sheet in an effort to ensure sufficient liquidity, including cash resources and available credit. We believe these strategies are appropriate for our portfolio of projects and the current industry environment and will continue to add shareholder value over the long-term.

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

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

Financial Condition***Capital Resources and Liquidity***

Our primary sources of cash for the six months ended June 30, 2009 were funds generated from the sale of natural gas and crude oil production and, to a lesser extent, the sales of properties during the period, as disclosed in Note 2 of the Notes to the Condensed Consolidated Financial Statements. Cash flows provided by operating activities and, to a lesser extent proceeds from the sales of properties were primarily used to fund our development and exploratory expenditures, in addition to payments for debt service, debt issuance costs, contributions to our pension plan and dividends. See below for additional discussion and analysis of cash flow.

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

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

	Six Months Ended June 30,	
	2009	2008
<i>(In thousands)</i>		
Cash Flows Provided by Operating Activities	\$ 300,385	\$ 276,411
Cash Flows Used in Investing Activities	(230,166)	(383,812)
Cash Flows (Used in) / Provided by Financing Activities	(68,472)	225,234
Net Increase in Cash and Cash Equivalents	\$ 1,747	\$ 117,833

Operating Activities. Key components impacting net operating cash flows are commodity prices, production volumes and operating costs. Net cash provided by operating activities in the first six months of 2009 increased by \$24.0 million over the first six months of 2008. This increase was mainly due to an increase in working capital changes as a result of a decrease in trade accounts receivable due to lower commodity prices and a decrease in accounts payable due to lower capital expenditures and lower commodity prices. Average realized natural gas prices decreased by 14% for the first six months of 2009 compared to the first six months of 2008 and average realized crude oil prices decreased by 14% compared to the same period. Equivalent production volumes increased by 13% for the six months ended June 30, 2009 compared to the six months ended June 30, 2008 as a result of higher natural gas production. We are unable to predict future commodity prices and, as a result, cannot provide any assurance about future levels of net cash provided by operating activities. Realized prices may continue to decline during 2009.

Table of Contents

Investing Activities. The primary uses of cash in investing activities were capital spending and exploration expenses. We established the budget for these amounts based on our current estimate of future commodity prices. Due to the volatility of commodity prices and new opportunities which may arise, our capital expenditures may be periodically adjusted during any given year. Cash flows used in investing activities decreased by \$153.6 million from the first half of 2008 compared to the first half of 2009. The decrease was due to a decrease of \$79.6 million in capital expenditures and acquisitions and an increase of \$78.5 million of proceeds from the sale of assets, partially offset by an increase of \$4.5 million in exploration expenditures.

Financing Activities. Cash flows used in financing activities increased by \$293.7 million from the first half of 2008 compared to the first half of 2009. This was primarily due to a decrease in net proceeds from the sale of common stock of \$316 million primarily due to our June 2008 issuance of 5,002,500 shares of common stock in a public offering for net proceeds of \$313.5 million. In addition, we paid \$10.4 million in cash for capitalized debt issuance costs, and dividends paid increased by \$0.3 million during the first half of 2009. Partially offsetting these changes previously discussed was a decrease of \$33 million in our net repayments on our revolving credit facility (\$52 million in net repayments in the first half of 2009 compared to \$85 million in net repayments in the first half of 2008).

At June 30, 2009, we had \$133 million of borrowings outstanding under our unsecured credit facility at a weighted-average interest rate of 3.9%. In April 2009, we entered into a new revolving credit facility and terminated our prior credit facility (see Note 4 to the Condensed Consolidated Financial Statements for further details). The new credit facility provides for an available credit line of \$500 million and contains an accordion feature allowing us to increase the available credit line to \$600 million, if any one or more of the existing banks or new banks agree to provide such increased commitment amount. The available credit line is subject to adjustment on the basis of the present value of estimated future net cash flows from proved oil and gas reserves (as determined by the banks based on our reserve reports and engineering reports) and certain other assets and the outstanding principal balance of our senior notes. We strive to manage our debt at a level below the available credit line in order to maintain excess borrowing capacity. Our revolving credit facility includes a covenant limiting our total debt. Management believes that, with internally generated cash, existing cash and availability under our revolving credit facility, we have the capacity to finance our spending plans and maintain our strong financial position. At the same time, we will closely monitor the capital markets.

Capitalization

Information about our capitalization is as follows:

<i>(Dollars in millions)</i>	June 30, 2009	December 31, 2008
Debt ⁽¹⁾	\$ 815.0	\$ 867.0
Stockholders Equity	1,836.5	1,790.6
Total Capitalization	\$ 2,651.5	\$ 2,657.6
Debt to Capitalization	31%	33%
Cash and Cash Equivalents	\$ 29.8	\$ 28.1

⁽¹⁾ Includes \$20 million and \$35.9 million of current portion of long-term debt at June 30, 2009 and December 31, 2008, respectively. Includes \$133 million and \$185 million of borrowings outstanding under our revolving credit facility at June 30, 2009 and December 31, 2008, respectively.

Table of Contents

During the six months ended June 30, 2009, we paid dividends of \$6.2 million (\$0.03 per share) on our common stock. A regular dividend has been declared for each quarter since we became a public company in 1990.

Capital and Exploration Expenditures

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

The following table presents major components of capital and exploration expenditures for the six months ended June 30, 2009 and 2008:

<i>(In millions)</i>	Six Months Ended	
	June 30,	
	2009	2008
Capital Expenditures		
Drilling and Facilities ⁽¹⁾	\$ 222.8	\$ 232.1
Leasehold Acquisitions	11.5	50.2
Acquisitions	0.2	79.3
Pipeline and Gathering	7.9	8.2
Other	1.3	3.5
	243.7	373.3
Exploration Expense	16.9	12.4
Total	\$ 260.6	\$ 385.7

⁽¹⁾ Includes Canadian currency translation effects of \$4.6 million and \$(3.8) million in 2009 and 2008, respectively.

For the full year of 2009, we plan to drill approximately 149 gross (120.0 net) wells. This 2009 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. We will continue to assess the natural gas and crude oil price environment and our liquidity position and may increase or decrease the capital and exploration expenditures accordingly.

Contractual Obligations

At June 30, 2009, we were obligated to make future payments under drilling rig commitments and firm gas transportation agreements. For further information, please refer to Firm Gas Transportation Agreements and Drilling Rig Commitments under Note 6 in the Notes to the Condensed Consolidated Financial Statements and in our Form 10-K.

Critical Accounting Policies and Estimates

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

Recently Adopted Accounting Standards

In February 2008, the Financial Accounting Standards Board (FASB) issued FASB Staff Position (FSP) No. FAS 157-2, Effective Date of FASB Statement No. 157, which granted a one year deferral (to fiscal years beginning after November 15, 2008, and interim periods within those fiscal years) for certain non-financial assets and liabilities measured on a nonrecurring basis to comply with SFAS No. 157. Effective January 1, 2009, we applied the provisions

Table of Contents

of Statement of Financial Accounting Standards (SFAS) No. 157 covered under FSP No. FAS 157-2 which did not have a material impact on our financial statements. For further information, please refer to Note 7 of the Notes to the Condensed Consolidated Financial Statements.

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

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

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

In April 2009, the FASB issued FSP No. FAS 107-1 and Accounting Principles Bulletin (APB) No. 28-1, *Interim Disclosures about Fair Value of Financial Instruments*, to require disclosures about fair value of financial instruments for publicly traded companies for both interim and annual periods. Historically, these disclosures were only required annually. The interim disclosures are intended to provide financial statement users with more timely and transparent information about the effects of current market conditions on an entity's financial instruments that are not otherwise reported at fair value. FSP No. FAS 107-1 became effective for interim reporting periods ending after June 15, 2009, and we have provided interim disclosures regarding the fair value of debt instruments in Note 4 of the Notes to the Condensed Consolidated Financial Statements. Comparative disclosures are only required for periods ending after the initial adoption. FSP No. FAS 107-1 did not have a material impact on our financial position, results of operations or cash flows.

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

In June 2009, the FASB issued SFAS No. 165, *Subsequent Events*, which requires entities to disclose the date through which they have evaluated subsequent events and whether the date corresponds with the release of their financial statements. In addition, a new concept of financial statements being available to be issued was introduced. SFAS No. 165 is effective for interim and annual periods ending after June 15, 2009. SFAS No. 165 did not have any impact on our financial position, results of operations or cash flows.

Table of Contents

Recently Issued Accounting Pronouncements

In July 2009, the FASB issued SFAS No. 168, *The FASB Accounting Standards Codification and the Hierarchy of Generally Accepted Accounting Principles* as the sole source of authoritative non-governmental U.S. generally accepted accounting principles (GAAP). The Codification is not intended to change U.S. GAAP; however, references to various accounting pronouncements and literature will differ from what is currently being used in practice. As of July 1, 2009, the FASB no longer issues Statements, Interpretations, Staff Positions or EITF Abstracts. All guidance in the Codification has an equal level of authority. SFAS No. 168 will be effective for financial statements that cover interim and annual periods ending after September 15, 2009. Once effective, it will supersede all accounting standards in U.S. GAAP, aside from those issued by the SEC. There will be no impact on our financial position, results of operations or cash flows as a result of the Codification.

In June 2009, the FASB issued SFAS No. 166, *Accounting for Transfers of Financial Assets*. SFAS No. 166 revises SFAS No. 140 and will require entities to provide more information about sales of securitized financial assets and similar transactions, particularly if the seller retains some risk to the assets. SFAS No. 166 will be effective at the beginning of the first fiscal year beginning after November 15, 2009. As we do not anticipate having any of these types of transactions in the near future, SFAS No. 166 is not expected to have any impact on our financial position, results of operations or cash flows.

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

Results of Operations

Second Quarters of 2009 and 2008 Compared

We reported net income in the second quarter of 2009 of \$25.5 million, or \$0.25 per share. For the second quarter of 2008, we reported net income of \$54.6 million, or \$0.55 per share. Net income decreased in the second quarter of 2009 by \$29.1 million, primarily due to a decrease in operating revenues and increases in interest expense and loss on sale of assets in the second quarter of 2009, partially offset by decreased operating and income tax expenses. Operating revenues decreased by \$44.0 million, largely due to decreases in natural gas production revenues and brokered natural gas revenues as well as crude oil and condensate revenues. Operating expenses decreased by \$21.1 million between periods due primarily to decreases in general and administrative expenses, brokered natural gas costs and taxes other than income, partially offset by increased depreciation, depletion and amortization and exploration expense. In addition, net income was impacted in the second quarter of 2009 by a loss on sale of assets as well as a decrease in expenses of \$10.8 million resulting from a combination of decreased income tax expense and higher interest and other expenses. Income tax expense was lower in the second quarter of 2009 as a result of a decrease in operating income, as discussed above, in addition to a decrease in the effective tax rate.

Table of Contents**Natural Gas Production Revenues**

Our average total company realized natural gas production sales price, including the realized impact of derivative instruments, was \$7.25 per Mcf for the three months ended June 30, 2009 compared to \$9.30 per Mcf for the comparable period of the prior year. These prices include the realized impact of derivative instrument settlements, which increased the price by \$4.15 per Mcf in 2009 and decreased the price by \$0.97 per Mcf in 2008. The following table excludes the unrealized loss from the change in fair value of our basis swaps of \$0.1 million for the quarter ended June 30, 2009 and the unrealized loss from the change in derivative fair value of \$2.9 million for the quarter ended June 30, 2008, which have been included within Natural Gas Production Revenues in the Condensed Consolidated Statement of Operations.

	Three Months Ended June 30,		Variance	
	2009	2008	Amount	Percent
Natural Gas Production (Mmcf)				
East	8,370	5,935	2,435	41%
Gulf Coast	9,380	7,711	1,669	22%
West	6,226	7,115	(889)	(12%)
Canada	354	1,343	(989)	(74%)
Total Company	24,330	22,104	2,226	10%
Natural Gas Production Sales Price (\$/Mcf)				
East	\$ 7.09	\$ 9.64	\$ (2.55)	(26%)
Gulf Coast	\$ 8.79	\$ 10.36	\$ (1.57)	(15%)
West	\$ 5.36	\$ 8.04	\$ (2.68)	(33%)
Canada	\$ 3.22	\$ 8.41	\$ (5.19)	(62%)
Total Company	\$ 7.25	\$ 9.30	\$ (2.05)	(22%)
Natural Gas Production Revenue (In thousands)				
East	\$ 59,343	\$ 57,212	\$ 2,131	4%
Gulf Coast	82,504	79,874	2,630	3%
West	33,355	57,222	(23,867)	(42%)
Canada	1,137	11,290	(10,153)	(90%)
Total Company	\$ 176,339	\$ 205,598	\$ (29,259)	(14%)
Price Variance Impact on Natural Gas Production Revenue (In thousands)				
East	\$ (21,344)			
Gulf Coast	(14,661)			
West	(16,717)			
Canada	(1,837)			
Total Company	\$ (54,559)			
Volume Variance Impact on Natural Gas Production Revenue (In thousands)				
East	\$ 23,475			
Gulf Coast	17,291			
West	(7,150)			
Canada	(8,316)			
Total Company	\$ 25,300			

The decrease in Natural Gas Production Revenue of \$29.3 million, excluding the impact of the unrealized losses discussed above, is due to primarily to the decrease in realized natural gas prices. In addition, natural gas production declined in the West due to natural decline and in

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Canada due to the sale of our Canadian properties in April 2009, reduced drilling activity and natural decline. Partially offsetting these decreases was an increase in natural gas production in the East region associated with an increase in the drilling program and initiation of production in Susquehanna County, Pennsylvania as well as in the Gulf Coast region due to the east Texas property acquisition in the second half of 2008 and increased drilling in the County Line field.

Table of Contents**Brokered Natural Gas Revenue and Cost**

	Three Months Ended June 30,		Variance	
	2009	2008	Amount	Percent
Sales Price (\$/Mcf)	\$ 4.83	\$ 12.15	\$ (7.32)	(60%)
Volume Brokered (Mmcf)	x 2,424	x 2,237	187	8%
Brokered Natural Gas Revenues (In thousands)	\$ 11,704	\$ 27,188		
Purchase Price (\$/Mcf)	\$ 4.41	\$ 10.79	\$ (6.38)	(59%)
Volume Brokered (Mmcf)	x 2,424	x 2,237	187	8%
Brokered Natural Gas Cost (In thousands)	\$ 10,684	\$ 24,140		
Brokered Natural Gas Margin (In thousands)	\$ 1,020	\$ 3,048	\$ (2,028)	(67%)
<i>(In thousands)</i>				
Sales Price Variance Impact on Revenue	\$ (17,756)			
Volume Variance Impact on Revenue	2,272			
	\$ (15,484)			
<i>(In thousands)</i>				
Purchase Price Variance Impact on Purchases	\$ 15,474			
Volume Variance Impact on Purchases	(2,018)			
	\$ 13,456			

The decreased brokered natural gas margin of \$2.0 million is a result of a decrease in sales price that outpaced the decrease in purchase price, partially offset by an increase in volumes brokered.

Table of Contents**Crude Oil and Condensate Revenues**

Our average total company realized crude oil sales price, including the realized impact of derivative instruments, was \$83.76 per Bbl for the second quarter of 2009 compared to \$98.68 per Bbl for the second quarter of 2008. These prices include the realized impact of derivative instrument settlements, which increased the price by \$30.78 in 2009 and decreased the price by \$21.19 per Bbl in 2008. There was no revenue impact from the unrealized change in crude oil and condensate derivative fair value for the three months ended June 30, 2009 and 2008.

	Three Months Ended June 30,		Variance	
	2009	2008	Amount	Percent
Crude Oil Production (Mbbbl)				
East	5	6	(1)	(17%)
Gulf Coast	145	136	9	7%
West	42	42		
Canada	2	5	(3)	(60%)
Total Company	194	189	5	3%
Crude Oil Sales Price (\$/Bbl)				
East	\$ 54.24	\$ 118.33	\$ (64.09)	(54%)
Gulf Coast	\$ 94.51	\$ 91.87	\$ 2.64	3%
West	\$ 52.15	\$ 118.18	\$ (66.03)	(56%)
Canada	\$ 45.14	\$ 96.89	\$ (51.75)	(53%)
Total Company	\$ 83.76	\$ 98.68	\$ (14.92)	(15%)
Crude Oil Revenue (In thousands)				
East	\$ 269	\$ 684	\$ (415)	(61%)
Gulf Coast	13,658	12,456	1,202	10%
West	2,189	4,961	(2,772)	(56%)
Canada	94	499	(405)	(81%)
Total Company	\$ 16,210	\$ 18,600	\$ (2,390)	(13%)
Price Variance Impact on Crude Oil Revenue (In thousands)				
East	\$ (293)			
Gulf Coast	382			
West	(2,772)			
Canada	(109)			
Total Company	\$ (2,792)			
Volume Variance Impact on Crude Oil Revenue (In thousands)				
East	\$ (122)			
Gulf Coast	820			
West				
Canada	(296)			
Total Company	\$ 402			

The decrease in realized crude oil prices, partially offset by an increase in crude oil production (due to an increase in Gulf Coast production), resulted in a net revenue decrease of \$2.4 million.

Table of Contents**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:

<i>(In thousands)</i>	Three Months Ended June 30,			
	2009		2008	
	Realized	Unrealized	Realized	Unrealized
Operating Revenues Increase / (Decrease) to Revenue				
Cash Flow Hedges				
Natural Gas Production	\$ 100,956	\$	\$ (21,414)	\$ (2,909)
Crude Oil	5,972		(4,004)	
Total Cash Flow Hedges	\$ 106,928	\$	\$ (25,418)	\$ (2,909)
Other Derivative Financial Instruments				
Natural Gas Basis Swaps		(126)		
Total Other Derivative Financial Instruments		(126)		
Total Cash Flow Hedges and Other Derivative Financial Instruments	\$ 106,928	\$ (126)	\$ (25,418)	\$ (2,909)

We are exposed to market risk on derivative instruments to the extent of changes in market prices of natural gas and oil. However, the market risk exposure on these derivative contracts is generally offset by the gain or loss recognized upon the ultimate sale of the commodity. Although notional contract amounts are used to express the volume of natural gas price agreements, the amounts that can be subject to credit risk in the event of non-performance by third parties are substantially smaller. We do not anticipate any material impact on our financial results due to non-performance by third parties. Our primary derivative contract counterparties are Bank of Montreal, BNP Paribas, Goldman Sachs, JPMorgan Chase and Morgan Stanley.

Operating Expenses

Total costs and expenses from operations decreased by \$21.1 million in the second quarter of 2009 compared to the same period of 2008. The primary reasons for this fluctuation are as follows:

General and Administrative expenses decreased by \$16.4 million from the second quarter of 2008 compared to the second quarter of 2009. This is primarily due to decreased stock compensation expense largely related to a reduction in supplemental employee compensation expense of \$11.3 million as well as a reduction in performance share expense of \$4.0 million.

Brokered Natural Gas Cost decreased by \$13.5 million from the second quarter of 2008 compared to the second quarter of 2009. See the preceding table titled Brokered Natural Gas Revenue and Cost for further analysis.

Depreciation, Depletion and Amortization increased by \$12.6 million from the second quarter of 2008 compared to the second quarter of 2009. This is primarily due to the impact on the DD&A rate of higher capital costs and higher natural gas production volumes, including the east Texas acquisition in August 2008.

Taxes Other Than Income decreased by \$8.3 million in the second quarter of 2009 compared with the second quarter of 2008 due to lower production taxes as a result of lower average natural gas and crude oil prices, partially offset by higher ad valorem taxes.

Exploration expense increased by \$3.1 million from the second quarter of 2008 compared to the second quarter of 2009 primarily due higher charges for idle contract rigs, partially offset by decreased geological and geophysical costs.

Interest Expense, Net

Interest expense, net increased by \$8.8 million in the second quarter of 2009 compared to the second quarter of 2008 primarily due to increased interest expense related to the \$492 million principal amount of debt we issued in our July and

Table of Contents

December 2008 private placements. Weighted-average borrowings under our credit facility based on daily balances were approximately \$190 million during the second quarter of 2009 compared to approximately \$195 million during the second quarter of 2008. The weighted-average effective interest rate on the credit facility decreased to approximately 4.2% during the second quarter of 2009 compared to approximately 4.5% during the second quarter of 2008.

Income Tax Expense

Income tax expense decreased by \$19.6 million due to a decrease in our pre-tax income. The effective tax rates for the second quarter of 2009 and 2008 were 34.9% and 37.8%, respectively. The effective tax rate was lower in the second quarter of 2009 primarily as a result of the sale of our Canadian properties and tax benefits associated with foreign tax credits.

Six Months of 2009 and 2008 Compared

We reported net income in the first six months of 2009 of \$73.1 million, or \$0.71 per share. For the first six months of 2008, we reported net income of \$100.6 million, or \$1.03 per share. Net income decreased in the first half of 2009 by \$27.5 million, primarily due to a decrease in operating revenues and increases in interest expense and loss on sale of assets in the second quarter of 2009, partially offset by decreased operating and income tax expenses. Operating revenues decreased by \$29.7 million, largely due to decreases in brokered natural gas and natural gas production revenues as well as crude oil and condensate revenues. Operating expenses decreased by \$8.0 million between periods due primarily to decreases in general and administrative expenses, brokered natural gas costs and taxes other than income, partially offset by increased depreciation, depletion and amortization and impairment of unproved properties, direct operations and exploration expense. In addition, net income was impacted in the first half of 2009 by a loss on sale of assets as well as an increase in expenses of \$1.5 million resulting from a combination of higher interest and other expenses and decreased income tax expense. Income tax expense was lower in the first half of 2009 as a result of a decrease in operating income, as discussed above, partially offset by a slight increase in the effective tax rate.

Table of Contents**Natural Gas Production Revenues**

Our average total company realized natural gas production sales price, including the realized impact of derivative instruments, was \$7.38 per Mcf for the six months ended June 30, 2009 compared to \$8.63 per Mcf for the comparable period of the prior year. These prices include the realized impact of derivative instrument settlements, which increased the price by \$3.74 per Mcf in 2009 and decreased the price by \$0.48 per Mcf in 2008. The following table excludes the unrealized gain from the change in fair value of our basis swaps of \$0.8 million for the six months ended June 30, 2009 and the unrealized loss from the change in derivative fair value of \$2.9 million for the six months ended June 30, 2008, which have been included within Natural Gas Production Revenues in the Condensed Consolidated Statement of Operations.

	Six Months Ended June 30,		Variance	
	2009	2008	Amount	Percent
Natural Gas Production (Mmcf)				
East	15,650	11,935	3,715	31%
Gulf Coast	19,743	15,116	4,627	31%
West	12,434	13,481	(1,047)	(8%)
Canada	958	2,589	(1,631)	(63%)
Total Company	48,785	43,121	5,664	13%
Natural Gas Production Sales Price (\$/Mcf)				
East	\$ 7.67	\$ 8.96	\$ (1.29)	(14%)
Gulf Coast	\$ 8.55	\$ 9.35	\$ (0.80)	(9%)
West	\$ 5.45	\$ 7.67	\$ (2.22)	(29%)
Canada	\$ 3.40	\$ 7.91	\$ (4.51)	(57%)
Total Company	\$ 7.38	\$ 8.63	\$ (1.25)	(14%)
Natural Gas Production Revenue (In thousands)				
East	\$ 120,048	\$ 106,921	\$ 13,127	12%
Gulf Coast	168,876	141,311	27,565	20%
West	67,737	103,442	(35,705)	(35%)
Canada	3,259	20,483	(17,224)	(84%)
Total Company	\$ 359,920	\$ 372,157	\$ (12,237)	(3%)
Price Variance Impact on Natural Gas Production Revenue (In thousands)				
East	\$ (20,178)			
Gulf Coast	(15,724)			
West	(27,631)			
Canada	(4,316)			
Total Company	\$ (67,849)			
Volume Variance Impact on Natural Gas Production Revenue (In thousands)				
East	\$ 33,305			
Gulf Coast	43,289			
West	(8,074)			
Canada	(12,908)			
Total Company	\$ 55,612			

The decrease in Natural Gas Production Revenue of \$12.2 million, excluding the impact of the unrealized gains and losses discussed above, is due to a decrease in realized natural gas prices. Increases in natural gas production in the Gulf Coast region due to the east Texas property

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acquisition in the second half of 2008 and increased drilling in the County Line field, as well as an increase in the East region associated with an increase in the drilling program and initiation of production in Susquehanna County, Pennsylvania. These increases previously discussed more than offset decreases in natural gas production in the West due to natural decline and in Canada due to the sale of our Canadian properties in April 2009, reduced drilling activity and natural decline.

Table of Contents**Brokered Natural Gas Revenue and Cost**

	Six Months Ended June 30,		Variance	
	2009	2008	Amount	Percent
Sales Price (\$/Mcf)	\$ 7.39	\$ 10.49	\$ (3.10)	(30%)
Volume Brokered (Mmcf)	x 6,099	x 5,990	109	2%
Brokered Natural Gas Revenues (In thousands)	\$ 45,085	\$ 62,808		
Purchase Price (\$/Mcf)	\$ 6.63	\$ 9.09	\$ (2.46)	(27%)
Volume Brokered (Mmcf)	x 6,099	x 5,990	109	2%
Brokered Natural Gas Cost (In thousands)	\$ 40,433	\$ 54,430		
Brokered Natural Gas Margin (In thousands)	\$ 4,652	\$ 8,378	\$ (3,726)	(44%)
<i>(In thousands)</i>				
Sales Price Variance Impact on Revenue	\$ (18,866)			
Volume Variance Impact on Revenue	1,143			
	\$ (17,723)			
<i>(In thousands)</i>				
Purchase Price Variance Impact on Purchases	\$ 14,988			
Volume Variance Impact on Purchases	(991)			
	\$ 13,997			

The decreased brokered natural gas margin of \$3.7 million is a result of a decrease in sales price that outpaced the decrease in purchase price, partially offset by an increase in volumes brokered.

Table of Contents**Crude Oil and Condensate Revenues**

Our average total company realized crude oil sales price, including the realized impact of derivative instruments, was \$79.55 per Bbl for the first half of 2009 compared to \$92.58 per Bbl for the first half of 2008. These prices include the realized impact of derivative instrument settlements, which increased the price by \$34.87 in 2009 and decreased the price by \$14.88 per Bbl in 2008. There was no revenue impact from the unrealized change in crude oil and condensate derivative fair value for the six months ended June 30, 2009 and 2008.

	Six Months Ended June 30,		Variance	
	2009	2008	Amount	Percent
Crude Oil Production (Mbbbl)				
East	9	12	(3)	(25%)
Gulf Coast	293	280	13	5%
West	75	76	(1)	(1%)
Canada	6	11	(5)	(45%)
Total Company	383	379	4	1%
Crude Oil Sales Price (\$/Bbl)				
East	\$ 46.90	\$ 103.89	\$ (56.99)	(55%)
Gulf Coast	\$ 90.72	\$ 88.11	\$ 2.61	3%
West	\$ 43.37	\$ 108.12	\$ (64.75)	(60%)
Canada	\$ 36.46	\$ 87.26	\$ (50.80)	(58%)
Total Company	\$ 79.55	\$ 92.58	\$ (13.03)	(14%)
Crude Oil Revenue (In thousands)				
East	\$ 410	\$ 1,227	\$ (817)	(67%)
Gulf Coast	26,561	24,657	1,904	8%
West	3,255	8,204	(4,949)	(60%)
Canada	226	999	(773)	(77%)
Total Company	\$ 30,452	\$ 35,087	\$ (4,635)	(13%)
Price Variance Impact on Crude Oil Revenue (In thousands)				
East	\$ (478)			
Gulf Coast	763			
West	(4,847)			
Canada	(316)			
Total Company	\$ (4,878)			
Volume Variance Impact on Crude Oil Revenue (In thousands)				
East	\$ (339)			
Gulf Coast	1,141			
West	(102)			
Canada	(457)			
Total Company	\$ 243			

The decrease in realized crude oil prices, partially offset by a slight increase in crude oil production, resulted in a net revenue decrease of \$4.6 million. Realized crude oil prices and production declined in all regions except for the Gulf Coast.

Table of Contents**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:

<i>(In thousands)</i>	Six Months Ended June 30,			
	2009		2008	
	Realized	Unrealized	Realized	Unrealized
Operating Revenues Increase / (Decrease) to Revenue				
Cash Flow Hedges				
Natural Gas Production	\$ 182,666	\$	\$ (20,802)	\$ (2,909)
Crude Oil	13,356		(5,638)	
Total Cash Flow Hedges	196,022		(26,440)	(2,909)
Other Derivative Financial Instruments				
Natural Gas Basis Swaps		815		
Total Other Derivative Financial Instruments		815		
Total Cash Flow Hedges and Other Derivative Financial Instruments	\$ 196,022	\$ 815	\$ (26,440)	\$ (2,909)

Operating Expenses

Total costs and expenses from operations decreased by \$8.0 million in the first six months of 2009 compared to the same period of 2008. The primary reasons for this fluctuation are as follows:

General and Administrative expenses decreased by \$26.9 million from the first half of 2008 compared to the first half of 2009. This is primarily due to decreased stock compensation expense largely related to a reduction in supplemental employee compensation expense of \$15.7 million as well as a reduction in performance share award expense of \$11.7 million.

Depreciation, Depletion and Amortization increased by \$26.9 million from the first half of 2008 compared to the first half of 2009. This is primarily due to the impact on the DD&A rate of higher capital costs and higher natural gas production volumes, including the east Texas acquisition in August 2008.

Brokered Natural Gas Cost decreased by \$14.0 million from the second quarter of 2008 compared to the second quarter of 2009. See the preceding table titled "Brokered Natural Gas Revenue and Cost" for further analysis.

Taxes Other Than Income decreased by \$12.3 million from the first half of 2008 compared to the first half of 2009 due to lower production taxes as a result of lower average natural gas and crude oil prices, partially offset by higher ad valorem taxes.

Direct Operations expenses increased by \$8.4 million from the first half of 2008 compared with the first half of 2009 primarily due to higher personnel and labor expenses and higher compressor, workover, and outside operated properties charges.

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Impairment of Unproved Properties increased by \$5.4 million from the first half of 2008 compared to the first half of 2009, primarily due to increased lease acquisition costs incurred in several exploratory and developmental areas in the East and in east Texas, including the Minden area, as well as the amortization of undeveloped costs associated with the east Texas acquisition in August 2008.

Exploration expense increased by \$4.5 million from the first half of 2008 compared to the first half of 2009 primarily due higher charges for idle contract rigs, partially offset by lower dry hole and geological and geophysical costs.

Table of Contents

Interest Expense, Net

Interest expense, net increased by \$17.1 million in the first half of 2009 compared to the first half of 2008 primarily due to increased interest expense related to the \$492 million principal amount of debt we issued in our July and December 2008 private placements. Weighted-average borrowings under our credit facility based on daily balances were approximately \$199 million during the first six months of 2009 compared to approximately \$176 million during the first six months of 2008. The weighted-average effective interest rate on the credit facility decreased to approximately 4.3% during the first half of 2009 compared to approximately 5.2% during the first half of 2008.

Income Tax Expense

Income tax expense decreased by \$15.6 million due to a decrease in our pre-tax income. The effective tax rates for the first six months of 2009 and 2008 were 36.4% and 36.3%, respectively.

Forward-Looking Information

The statements regarding future financial performance and results, market prices and the other statements which are not historical facts contained in this report are forward-looking statements. The words expect, project, estimate, believe, anticipate, intend, budget, plan, predict and similar expressions are also intended to identify forward-looking statements. Such statements involve risks and uncertainties, including, but not limited to, market factors, market prices (including regional basis differentials) of natural gas and oil, results for future drilling and marketing activity, future production and costs and other factors detailed herein and in our other Securities and Exchange Commission filings. Should one or more of these risks or uncertainties materialize, or should underlying assumptions prove incorrect, actual outcomes may vary materially from those indicated.

ITEM 3. Quantitative and Qualitative Disclosures about Market Risk

Market Risk

Our primary market risk is exposure to oil and natural gas prices. Realized prices are mainly driven by worldwide prices for oil and spot market prices for North American natural gas production. Commodity prices are volatile and unpredictable.

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

Derivative Instruments and Hedging Activity

Our hedging strategy is designed to reduce the risk of price volatility for our production in the natural gas and crude oil markets. A hedging committee that consists of members of senior management oversees our hedging activity. Our hedging arrangements apply to only a portion of our production and provide only partial price protection. These hedging arrangements limit the benefit to us of increases in prices, but offer protection in the event of price declines. Further, if our counterparties defaulted, this protection might be limited as we might not receive the benefits of the hedges. Please read the discussion below as well as Note 7 of the Notes to the Condensed Consolidated Financial Statements for a more detailed discussion of our hedging arrangements.

As of June 30, 2009, we had 26 cash flow hedges open: 14 natural gas price collar arrangements, 10 natural gas price swap arrangements and two crude oil price swap arrangements. During the first half of 2009, we entered into six new derivative contracts covering anticipated natural gas production for 2012. These natural gas basis swaps did not qualify for hedge accounting under SFAS No. 133. These natural gas basis swaps mitigate the risk associated with basis differentials that may expand or increase over time, thus reducing the exposure and risk of basis fluctuations.

Table of Contents

As of June 30, 2009, we had the following outstanding commodity derivatives:

Commodity	Derivative Type	Weighted-Average Contract Price ⁽¹⁾		Volume		Contract Period	Net Unrealized Gain (In thousands)
Derivatives designated as Hedging Instruments under Statement 133							
Natural Gas	Collar	\$12.39 / \$9.40	per Mcf	23,820	Mmcf	2009	\$ 115,351
Natural Gas	Swap	\$11.43	per Mcf	19,295	Mmcf	2010	93,354
Natural Gas	Swap	\$12.18	per Mcf	8,106	Mmcf	2009	60,323
Crude Oil	Swap	\$125.25	per Bbl	184	Mbbl	2009	11,462
Crude Oil	Swap	\$125.00	per Bbl	365	Mbbl	2010	17,912
							\$ 298,402
Derivatives not qualifying as Hedging Instruments under Statement 133							
Natural Gas	Basis Swap	\$(0.27)	per Mcf	16,123	Mmcf	2012	810
							\$ 299,212

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

The amounts set forth under the net unrealized gain column in the tables above represent our total unrealized gain position at June 30, 2009 and do not include the impact of nonperformance risk. Also impacting the total unrealized net gain (reflecting the net receivable position) in accumulated other comprehensive income / (loss) in the Condensed Consolidated Balance Sheet is a reduction of \$1.8 million related to our assessment of our counterparties' nonperformance risk. This risk was primarily evaluated by reviewing credit default swap spreads for the various financial institutions in which we have derivative transactions.

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

During the first half of 2009, natural gas price swaps covered 7,973 Mmcf, or 16%, of our first half of 2009 gas production at an average price of \$12.18 per Mcf.

We had one crude oil price swap covering 181 Mbbl, or 47%, of our first six months of 2009 oil production at a price of \$125.25 per Bbl.

From time to time, we enter into natural gas and crude oil collar agreements with counterparties to hedge price risk associated with a portion of our production. These cash flow hedges are not held for trading purposes. Under the collar arrangements, if the index price rises above the ceiling price, we pay the counterparty. If the index price falls below the floor price, the counterparty pays us. During the first six months of 2009, natural gas price collars covered 23,433 Mmcf, or 48%, of our first half of 2009 gas production, with a weighted-average floor of \$9.40 per Mcf and a weighted-average ceiling of \$12.39 per Mcf.

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

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

Table of Contents**Fair Market Value of Financial Instruments**

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

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

Long-Term Debt

	June 30, 2009		December 31, 2008	
	Carrying Amount	Estimated Fair Value	Carrying Amount	Estimated Fair Value
<i>(In thousands)</i>				
Long-Term Debt	\$ 815,000	\$ 816,698	\$ 867,000	\$ 807,508
Current Maturities	(20,000)	(20,682)	(35,857)	(35,796)
Long-Term Debt, excluding Current Maturities	\$ 795,000	\$ 796,016	\$ 831,143	\$ 771,712

ITEM 4. Controls and Procedures

As of the end of the current reported period covered by this report, the Company carried out an evaluation, under the supervision and with the participation of the Company's management, including the Company's Chief Executive Officer and Chief Financial Officer, of the effectiveness of the design and operation of the Company's disclosure controls and procedures pursuant to Rules 13a-15 and 15d-15 of the Securities Exchange Act of 1934 (the Exchange Act). Based upon that evaluation, the Chief Executive Officer and Chief Financial Officer concluded that the Company's disclosure controls and procedures are effective, in all material respects, with respect to the recording, processing, summarizing and reporting, within the time periods specified in the Commission's rules and forms, of information required to be disclosed by the Company in the reports that it files or submits under the Exchange Act.

There were no changes in the Company's internal control over financial reporting that occurred during the second quarter of 2009 that have materially affected, or are reasonably likely to materially affect, the Company's internal control over financial reporting.

PART II. OTHER INFORMATION**ITEM 1A. Risk Factors**

For additional information about the risk factors facing the Company, see Item 1A of Part I of the Company's Annual Report on Form 10-K for the year ended December 31, 2008.

ITEM 2. Unregistered Sales of Equity Securities and Use of Proceeds***Issuer Purchases of Equity Securities***

The Board of Directors has authorized a share repurchase program under which the Company may purchase shares of common stock in the open market or in negotiated transactions. There is no expiration date associated with the authorization. During the six months ended June 30, 2009,

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the Company did not repurchase any shares of common stock. All purchases executed to date have been through open market transactions. The maximum number of shares that may yet be purchased under the plan as of June 30, 2009 was 4,795,300.

Table of Contents

Increase in Authorized Shares

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

ITEM 4. Submission of Matters to a Vote of Security Holders

On April 28, 2009, the Company held its Annual Meeting of Stockholders. At this meeting, the Company's stockholders voted on the following four matters:

the election of three directors;

the approval of an amendment to the Company's Certificate of Incorporation to increase the authorized Common Stock of the Company from 120,000,000 shares to 240,000,000 shares;

the reapproval of the material terms of the performance goals under the 2004 Incentive Plan; and

the ratification of the appointment of PricewaterhouseCoopers LLP as the independent registered public accounting firm for the Company for its 2009 fiscal year.

Of the 103,637,883 shares entitled to vote, 93,124,515 were present at the meeting in person or represented by proxy. Below are the results of the voting.

Shareholders voted to re-elect three directors by the following vote:

Rhys J. Best

For:	92,764,251
Against:	338,222
Withheld:	22,042

Robert Kelley

For:	92,799,548
Against:	306,569
Withheld:	18,398

P. Dexter Peacock

For:	90,257,505
Against:	2,848,203
Withheld:	18,807

The terms of office of directors David M. Carmichael, Dan O. Dinges, Robert L. Keiser and William P. Vititoe continued beyond the meeting date.

Shareholders approved an amendment to the Company's Certificate of Incorporation to increase the authorized Common Stock of the Company from 120,000,000 shares to 240,000,000 shares by the following vote:

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For	78,756,303
Against	14,340,195
Abstain	28,017

Shareholders reapproved the material terms of the performance goals under the 2004 Incentive Plan by the following vote:

For	85,146,157
Against	2,075,626
Abstain	84,312
Broker Non-Votes	5,818,420

Table of Contents

Shareholders ratified the appointment of PricewaterhouseCoopers LLP as the independent registered public accounting firm for the Company for its 2009 fiscal year by the following vote:

For	90,155,402
Against	2,951,310
Abstain	17,803

ITEM 6. Exhibits

- 3.1 Certificate of Incorporation of the Company (Registration Statement No. 33- 32553).
- 3.2 Certificate of Amendment of Certificate of Incorporation (Form 8-K for July 1, 2002).
- 3.3 Certificate of Increase of Shares Designated Series A Junior Participating Preferred Stock (Form 8-K for July 1, 2002).
- 3.4 Certificate of Amendment of Certificate of Incorporation (Form 8-K for June 1, 2006).
- 3.5 Certificate of Increase of Shares Designated Series A Junior Participating Preferred Stock (Form 8-K for June 1, 2006).
- 3.6 Certificate of Amendment of Certificate of Incorporation (Form 8-K for April 29, 2009).
- 3.7 Certificate of Decrease of Shares Designated as Series A Junior Participating Preferred Stock (Form 8-K for April 29, 2009).
- 4.1 Credit Agreement, dated as of April 24, 2009, among the Company, JPMorgan Chase Bank, N.A., as Administrative Agent, Banc of America Securities LLC, as Syndication Agent, Bank of Montreal, as Documentation Agent, and the Lenders party thereto (Form 8-K for April 24, 2009).
- 15.1 Awareness letter of PricewaterhouseCoopers LLP
- 31.1 302 Certification Chairman, President and Chief Executive Officer
- 31.2 302 Certification Vice President and Chief Financial Officer
- 32.1 906 Certification
- *101.INS XBRL Instance Document
- *101.SCH XBRL Taxonomy Extension Schema Document
- *101.CAL XBRL Taxonomy Extension Calculation Linkbase Document
- *101.LAB XBRL Taxonomy Extension Label Linkbase Document
- *101.PRE XBRL Taxonomy Extension Presentation Linkbase Document
- *101.DEF XBRL Taxonomy Extension Definition Linkbase Document

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

Table of Contents

SIGNATURES

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

CABOT OIL & GAS CORPORATION

(Registrant)

July 30, 2009

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

Chief Executive Officer

(Principal Executive Officer)

July 30, 2009

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

(Principal Financial Officer)

July 30, 2009

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

(Principal Accounting Officer)