PETROHAWK ENERGY CORP
Form 10-Q
August 04, 2009
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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

Commission file number 001-33334

PETROHAWK ENERGY CORPORATION

(Exact name of registrant as specified in its charter)

Delaware	**86-0876964**
(State or other jurisdiction of	**(I.R.S. Employer**

incorporation or organization)	Identification Number)

1000 Louisiana, Suite 5600, Houston, Texas 77002

(Address of principal executive offices including ZIP code)

(832) 204-2700

(Registrant s telephone number)

Securities registered pursuant to Section 12(b) of the Act:

Title of each class	Name of each exchange on which registered
Common Stock, par value $.001 per share	**New York Stock Exchange**

Securities registered pursuant to Section 12(g) of the Act: None

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 (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. Yes x No ¨

Indicate by check mark whether the registrant has submitted electronically and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T (§ 229.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files). Yes x No ¨

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

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

Indicate by check mark whether the Registrant is a shell company (as defined in Rule 12b-2 of the Exchange Act). Yes ¨ No x

As of July 31, 2009 the Registrant had 275,825,805 shares of Common Stock, $.001 par value, outstanding.

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Special note regarding forward-looking statements

This report on Form 10-Q contains forward-looking statements within the meaning of the federal securities laws. All statements, other than statements of historical facts, concerning, among other things, planned capital expenditures, potential increases in oil and natural gas production, the number of anticipated wells to be drilled in the future, future cash flows and borrowings, pursuit of potential acquisition opportunities, our financial position, business strategy and other plans and objectives for future operations, are forward-looking statements. These forward-looking statements are identified by their use of terms and phrases such as may, expect, estimate, project, plan, believe, intend, achievable, will, continue, potential, should, could and similar terms and phrases. Although we believe that the expectations reflected in these forward-looking statements are reasonable, they do involve certain assumptions, risks and uncertainties. The actual results could differ materially from those anticipated in these forward-looking statements. One should consider carefully the statements under the Risk Factors section of this report and other sections of this report, as well as those described in our Form 10-K, as amended for the year ended December 31, 2008, which describe factors that could cause our actual results to differ from those set forth in the forward-looking statements, including, but not limited to, the following factors:

- our ability to successfully develop our large inventory of undeveloped acreage primarily held in resource-style areas in Louisiana, Arkansas and Texas, including our resource-style plays such as the Haynesville, Fayetteville and Eagle Ford Shales;
- the volatility in commodity prices for oil and natural gas, including continued declines in prices;
- the possibility that the industry may be subject to future regulatory or legislative actions (including any additional taxes and changes in environmental regulation);
- the possibility that the United States economy remains in an extended recessionary period, which would negatively impact the price of commodities, including oil and natural gas;
- the presence or recoverability of estimated oil and natural gas reserves and the actual future production rates and associated costs;
- the possibility that production decline rates in some of our resource-style plays are greater than we expect;
- our ability to generate sufficient cash flow from operations, borrowings or other sources to enable us to fully develop our undeveloped acreage positions;
- our ability to replace oil and natural gas reserves;
- environmental risks;
- drilling and operating risks;
- exploration and development risks;

competition, including competition for acreage in resource-style areas;

management s ability to execute our plans to meet our goals;

our ability to retain key members of senior management and key technical employees;

our ability to obtain goods and services, such as drilling rigs and tubulars, and access to adequate gathering systems and pipeline take-away capacity, to support our drilling program;

our ability to secure firm transportation for natural gas we produce and to sell natural gas at market prices;

general economic conditions, whether internationally, nationally or in the regional and local market areas in which we do business, may be less favorable than expected, including the possibility that the

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- current economic recession and credit crisis in the United States will be severe and prolonged, which could adversely affect the demand for oil and natural gas and make it difficult to access financial markets;

- continued hostilities in the Middle East and other sustained military campaigns or acts of terrorism or sabotage; and

- other economic, competitive, governmental, legislative, regulatory, geopolitical and technological factors that may negatively impact our business, operations or pricing.

All forward-looking statements are expressly qualified in their entirety by the cautionary statements in this paragraph and elsewhere in this document. Other than as required under the securities laws, we do not assume a duty to update these forward-looking statements, whether as a result of new information, subsequent events or circumstances, changes in expectations or otherwise.

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PART I. FINANCIAL INFORMATION

Item 1. Condensed Consolidated Financial Statements (unaudited)

PETROHAWK ENERGY CORPORATION

CONDENSED CONSOLIDATED STATEMENTS OF OPERATIONS (Unaudited)

(In thousands, except per share amounts)

	Three Months Ended June 30,		Six Months Ended June 30,	
	2009	**2008**	**2009**	**2008**
Operating revenues:				
Oil and natural gas	$ 163,983	$ 304,633	$ 337,745	$ 519,571
Marketing	63,317		153,010	
Total operating revenues	227,300	304,633	490,755	519,571
Operating expenses:				
Marketing	60,292		145,136	
Production:				
Lease operating	18,704	12,903	35,115	25,297
Workover and other	205	1,249	928	1,786
Taxes other than income	12,537	14,036	24,717	25,000
Gathering, transportation and other	22,633	10,944	43,127	20,467
General and administrative	23,992	17,214	43,631	33,368
Depletion, depreciation and amortization	84,435	86,694	198,691	169,821
Full cost ceiling impairment			1,732,486	
Total operating expenses	222,798	143,040	2,223,831	275,739
Income (loss) from operations	4,502	161,593	(1,733,076)	243,832
Other (expenses) income:				
Net gain (loss) on derivative contracts	16,006	(277,605)	197,928	(420,346)
Interest expense and other	(55,880)	(35,154)	(111,948)	(62,691)
Total other (expenses) income	(39,874)	(312,759)	85,980	(483,037)
Loss before income taxes	(35,372)	(151,166)	(1,647,096)	(239,205)
Income tax benefit	13,368	58,400	625,339	90,827
Net loss available to common stockholders	$ (22,004)	$ (92,766)	$ (1,021,757)	$ (148,378)
Net loss per share of common stock:				
Basic	$ (0.08)	$ (0.45)	$ (3.84)	$ (0.76)
Diluted	$ (0.08)	$ (0.45)	$ (3.84)	$ (0.76)
Weighted average shares outstanding:				
Basic	274,146	206,490	266,145	195,060

Diluted	274,146	206,490	266,145	195,060

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

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PETROHAWK ENERGY CORPORATION

CONDENSED CONSOLIDATED BALANCE SHEETS (Unaudited)

(In thousands, except share and per share amounts)

	June 30, 2009	December 31, 2008
Current assets:		
Cash	$ 2,738	$ 6,883
Marketable securities	17,020	123,009
Accounts receivable	171,008	277,349
Receivables from derivative contracts	239,558	201,128
Prepaids and other	51,961	40,063
Total current assets	482,285	648,432
Oil and natural gas properties (full cost method):		
Evaluated	5,572,026	4,894,357
Unevaluated	2,262,183	2,287,968
Gross oil and natural gas properties	7,834,209	7,182,325
Less - accumulated depletion	(4,035,272)	(2,111,038)
Net oil and natural gas properties	3,798,937	5,071,287
Other operating property and equipment:		
Gas gathering system and equipment	346,445	190,054
Other operating assets	22,851	20,271
Gross other operating property and equipment	369,296	210,325
Less - accumulated depreciation	(17,349)	(11,106)
Net other operating property and equipment	351,947	199,219
Other noncurrent assets:		
Goodwill	932,802	933,058
Deferred income taxes	175,361	
Debt issuance costs, net of amortization	38,802	30,477
Receivables from derivative contracts	49,507	23,399
Other	1,976	1,457
Total assets	$ 5,831,617	$ 6,907,329
Current liabilities:		
Accounts payable and accrued liabilities	$ 518,653	$ 639,432
Deferred income taxes	75,109	77,454
Liabilities from derivative contracts	357	
Long-term debt	35,244	9,426
Total current liabilities	629,363	726,312

Long-term debt	2,398,101	2,283,874
Other noncurrent liabilities:		
Liabilities from derivative contracts	2,719	
Asset retirement obligations	30,227	28,644
Deferred income taxes		460,913
Other	3,743	2,676
Commitments and contingencies (Note 7)		
Stockholders equity:		
Common stock: 500,000,000 and 300,000,000 shares of $.001 par value authorized at June 30, 2009 and December 31, 2008; 275,812,260 and 252,364,143 shares issued and outstanding at June 30, 2009 and December 31, 2008, respectively	276	252
Additional paid-in capital	4,039,787	3,655,500
Accumulated deficit	(1,272,599)	(250,842)
Total stockholders equity	2,767,464	3,404,910
Total liabilities and stockholders equity	$ 5,831,617	$ 6,907,329

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

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PETROHAWK ENERGY CORPORATION

CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS (Unaudited)

(In thousands)

	Six Months Ended June 30, 2009	Six Months Ended June 30, 2008
Cash flows from operating activities:		
Net loss	$ (1,021,757)	$ (148,378)
Adjustments to reconcile net loss to net cash provided by operating activities:		
Depletion, depreciation and amortization	198,691	169,821
Full cost ceiling impairment	1,732,486	
Income tax benefit	(625,339)	(90,827)
Stock-based compensation	6,617	5,679
Net unrealized (gain) loss on derivative contracts	(18,419)	366,580
Other	9,460	81
Change in assets and liabilities:		
Accounts receivable	103,432	(79,109)
Prepaids and other	(11,898)	(2,107)
Accounts payable and accrued liabilities	(47,708)	64,445
Other	551	2,404
Net cash provided by operating activities	326,116	288,589
Cash flows from investing activities:		
Oil and natural gas capital expenditures	(748,102)	(1,394,107)
Proceeds received from sale of oil and natural gas properties		110,900
Marketable securities purchased	(763,092)	(1,116,098)
Marketable securities redeemed	869,081	626,387
Decrease in restricted cash		269,837
Other operating property and equipment expenditures	(145,351)	(31,041)
Net cash used in investing activities	(787,464)	(1,534,122)
Cash flows from financing activities:		
Proceeds from exercise of options and warrants	1,956	10,260
Proceeds from issuance of common stock	385,000	1,069,213
Offering costs	(9,031)	(44,717)
Proceeds from borrowings	634,674	1,596,000
Repayment of borrowings	(542,159)	(1,367,401)
Debt issue costs	(13,237)	(18,559)
Net cash provided by financing activities	457,203	1,244,796
Net decrease in cash	(4,145)	(737)
Cash at beginning of period	6,883	1,812
Cash at end of period	$ 2,738	$ 1,075

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

PETROHAWK ENERGY CORPORATION

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS (Unaudited)

1. FINANCIAL STATEMENT PRESENTATION

During interim periods, Petrohawk Energy Corporation (referred to as Petrohawk or the Company) follows the accounting policies disclosed in its 2008 Annual Report on Form 10-K, as amended, and filed with the Securities and Exchange Commission (SEC). Please refer to the footnotes in the 2008 Form 10-K when reviewing interim financial results.

These unaudited condensed consolidated financial statements reflect, in the opinion of the Company s management, all adjustments, consisting only of normal and recurring adjustments, necessary to present fairly the financial position as of, and results of operations for, the periods presented. Interim period results are not necessarily indicative of results of operations or cash flows for the full year. Certain prior year amounts have been reclassified to conform to the current year presentation. We have evaluated events or transactions through August 4, 2009 in conjunction with the preparation of these condensed consolidated financial statements.

Marketable Securities

The Company invests a portion of its cash in money market mutual funds which are highly liquid marketable securities. The Company accounts for marketable securities in accordance with Financial Accounting Standards Board s (FASB) Statement of Financial Accounting Standards (SFAS) No. 115, *Accounting for Certain Investments in Debt and Equity Securities* and classifies marketable securities as trading, available-for-sale, or held-to-maturity. The appropriate classification of its marketable securities is determined at the time of purchase and reevaluated at each balance sheet date.

At June 30, 2009 and December 31, 2008, the Company held approximately $17.0 million and $123.0 million, respectively of marketable securities which have been classified and accounted for as trading securities. Trading securities are recorded at fair value with realized gains and losses reported in *Interest expense and other* in the condensed consolidated statements of operations.

Oil and Natural Gas Properties

The Company accounts for its oil and natural gas producing activities using the full cost method of accounting as prescribed by the SEC. Accordingly, all costs incurred in the acquisition, exploration, and development of proved oil and natural gas properties, including the costs of abandoned properties, dry holes, geophysical costs, and annual lease rentals are capitalized. All general and administrative corporate costs unrelated to drilling activities are expensed as incurred. Sales or other dispositions of oil and natural gas properties are accounted for as adjustments to capitalized costs, with no gain or loss recorded unless the ratio of cost to proved reserves would significantly change. Depletion of evaluated oil and natural gas properties is computed on the units of production method based on proved reserves. The net capitalized costs of proved oil and natural gas properties are subject to a full cost ceiling limitation in which the costs are not allowed to exceed their related estimated future net revenues discounted at 10%, net of tax considerations. Under Staff Accounting Bulletin Topic 12.D.3.c., the Company may utilize the prices in effect on a date subsequent to the end of a reporting period when the full cost ceiling limitation was exceeded at the end of a reporting period and subsequent pricing exceeds pricing at the end of the reporting period. This option will no longer be available to the Company starting December 31, 2009 due to adoption of the new oil and gas reporting requirements as described below under *Recently Issued Accounting Pronouncements*.

Costs associated with unevaluated properties are excluded from the full cost pool until the Company has made a determination as to the existence of proved reserves. The Company reviews its unevaluated properties at the end of each quarter to determine whether the costs incurred should be transferred to the full cost pool and thereby subject to amortization.

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Marketing Revenue and Expense

During the fourth quarter of 2008, the Company began purchasing and selling third party natural gas produced from wells it operates. The revenues and expenses related to these marketing activities are reported on a gross basis as part of operating revenues and operating expenses. Marketing revenues are recorded at the time natural gas is physically delivered to third parties at a fixed or index price. Marketing expenses attributable to gas purchases are recorded as the Company takes physical title to natural gas and transports the purchased volumes to the point of sale.

Risk Management Activities

The Company follows SFAS No. 133, *Accounting for Derivative Instruments and Hedging Activities* (SFAS 133), as amended. From time to time, the Company may hedge a portion of its forecasted oil and natural gas production. Derivative contracts entered into by the Company have consisted of transactions in which the Company hedges the variability of cash flow related to a forecasted transaction. The Company has elected to not designate any of its positions for hedge accounting. Accordingly, the Company records the net change in the mark-to-market valuation of these positions, as well as payments and receipts on settled contracts, in *Net gain (loss) on derivative contracts* on the condensed consolidated statements of operations.

Goodwill

Goodwill represents the excess of the purchase price over the estimated fair value of the assets acquired net of the fair value of liabilities assumed in an acquisition. SFAS No. 142, *Goodwill and Other Intangible Assets* requires that intangible assets with indefinite lives, including goodwill, be evaluated on an annual basis for impairment or more frequently if an event occurs or circumstances change that could potentially result in impairment.

The goodwill impairment test requires the allocation of goodwill and all other assets and liabilities to reporting units. If the fair value of the reporting unit is less than the book value (including goodwill), then goodwill is reduced to its implied fair value and the amount of the write-down is charged against earnings. The assumptions used by the Company in calculating its reporting unit fair value at the time of the test include the Company s market capitalization and discounted future cash flows based on estimated reserves and production, future costs and future oil and natural gas prices. Adverse changes to any of these factors could lead to an impairment of all or a portion of the Company s goodwill in future periods.

The Company completed its annual goodwill impairment test during the third quarter of 2008 and no goodwill impairments were deemed necessary. As a result of the full cost ceiling impairments recorded by the Company, the Company reviewed its goodwill for impairment as of March 31, 2009 and December 31, 2008. Based on these reviews, no goodwill impairment was deemed necessary.

Recently Issued Accounting Pronouncements

In June 2009, the FASB issued SFAS No. 168, *The FASB Accounting Standards Codification and the Hierarchy of Generally Accepted Accounting Principles* (SFAS 168). SFAS 168 will become the source of authoritative United States generally accepted accounting principles (GAAP) recognized by the FASB to be applied by nongovernmental entities. Rules and interpretive releases of the SEC under authority of federal securities laws are also sources of authoritative GAAP for SEC registrants. On the effective date of this Statement, the Codification will supersede all then-existing non-SEC accounting and reporting standards. All other non grandfathered non-SEC accounting literature not included in the Codification will become non authoritative. This statement is effective for financial statements issued for interim and annual periods ending after September 15, 2009. The Company does not expect the adoption of SFAS 168 to have an impact on the Company s results of operations, financial condition or cash flows.

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In May 2009, the FASB issued SFAS No. 165, *Subsequent Events* (SFAS 165) which establishes general standards of accounting for and disclosure of events that occur after the balance sheet date but before financial statements are issued or are available to be issued. SFAS 165 is effective for interim and annual reporting periods ending after June 15, 2009. The Company adopted the provisions of SFAS 165 for the period ended June 30, 2009. There was no impact on the Company s operating results, financial position or cash flows.

In April 2009, the FASB issued FASB Staff Position (FSP) No. FAS 107-1 and Accounting Principles Board (APB) 28-1, *Interim Disclosures about Fair Value of Financial Instruments,* (FAS 107-1) to amend SFAS No. 107, *Disclosures about Fair Value of Financial Instruments* and APB 28, *Interim Financial Reporting*. FAS 107-1 changes the reporting requirements on certain fair value disclosures of financial instruments to include interim reporting periods. The Company adopted FAS 107-1 in the second quarter of 2009. There was no impact on the Company s operating results, financial position or cash flows; however additional disclosures were added to the accompanying notes to the condensed consolidated financial statements for the Company s fair value of financial instruments. See Note 5 *Fair Value Measurements* for more details.

In April 2009, the FASB issued FSP No. FAS 115-2 and FAS 124-2, *Recognition and Presentation of Other-Than-Temporary Impairments,* (FAS 115-2) to amend SFAS No 115, *Accounting for Certain Investments in Debt and Equity Securities* and SFAS No. 124, *Accounting for Certain Investments Held by Not-for-Profit Organizations*. FAS 115-2 expands other-than-temporary impairment guidance for debt securities to enhance the application of the guidance and improve the presentation and disclosure of other-than temporary impairments on debt and equity securities within the financial statements. The adoption of FAS 115-2 in the second quarter of 2009 did not have a significant impact on the Company s operating results, financial position or cash flows.

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,* (FAS 157-4) to amend SFAS No. 157, *Fair Value Measurements,* (SFAS 157). FAS 157-4 provides additional guidance for estimating fair value in accordance with SFAS 157 when the volume and level of activity for an asset or liability has significantly decreased. In addition, FAS 157-4 includes guidance on identifying circumstances that indicate a transaction is not orderly. The adoption of FAS 157-4 in the second quarter of 2009 did not have a significant impact on the Company s operating results, financial position or cash flows.

On December 31, 2008, the SEC published the final rules and interpretations updating its oil and gas reporting requirements. Many of the revisions are updates to definitions in the existing oil and gas rules to make them consistent with the petroleum resource management system, which is a widely accepted standard for the management of petroleum resources that was developed by several industry organizations. Key revisions include changes to the pricing used to estimate reserves utilizing a 12-month average price rather than a single day spot price and elimination of the ability to utilize subsequent prices to the end of a reporting period when the full cost ceiling was exceeded and subsequent pricing exceeds pricing at the end of a reporting period; the ability to include nontraditional resources in reserves; the use of new technology for determining reserves; and permitting disclosure of probable and possible reserves. The SEC will require companies to comply with the amended disclosure requirements for registration statements filed after January 1, 2010, and for annual reports on Form 10-K for fiscal years ending on or after December 15, 2009. Early adoption is not permitted. The Company is currently assessing the impact that the adoption will have on the Company s disclosures, operating results, financial position and cash flows.

In October 2008, the FASB issued FSP No. SFAS 157-3, *Determining the Fair Value of a Financial Asset When the Market for That Asset Is Not Active* (FSP 157-3), which clarifies the application of SFAS 157 in an inactive market and illustrates how an entity would determine fair value when the market for a financial asset is not active. The Company determined whether the market for its derivative contracts was active or inactive based on transaction volume for such contracts. FSP 157-3 was effective upon issuance, including prior periods for which financial statements have not been issued. The guidance provided by FSP 157-3 did not have a material impact on the Company s operating results, financial position or cash flows.

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In March 2008, the FASB issued SFAS No. 161, *Disclosures about Derivative Instruments and Hedging Activities an amendment of FASB Statement No. 133* (SFAS 161). SFAS 161 requires entities that utilize derivative contracts to provide qualitative disclosures about their objectives and strategies for using such instruments, as well as any details of credit-risk-related contingent features contained within derivatives. SFAS 161 also requires entities to disclose additional information about the amounts and location of derivatives located within the financial statements, how the provisions of SFAS 133 have been applied, and the impact that hedges have on an entity s operating results, financial position or cash flows. The Company adopted SFAS 161 on January 1, 2009. There was no impact on the Company s operating results, financial position or cash flows; however additional disclosures were added to the accompanying notes to the condensed consolidated financial statements for the Company s open derivative contracts. See Note 8 *Derivatives* for more details.

In December 2007, the FASB issued SFAS No. 141 (Revised 2007), *Business Combinations* (SFAS 141R), and SFAS No. 160, *Accounting and Reporting of Noncontrolling Interest in Consolidated Financial Statements, an amendment of ARB No. 51* (SFAS 160). SFAS 141R and SFAS 160 significantly change the accounting for and reporting of business combination transactions and noncontrolling (minority) interests within the financial statements. SFAS 141R retains the fundamental requirements in SFAS No. 141, *Business Combinations*, while providing additional definitions, such as the definition of the acquirer in a purchase and improvements in the application of how the acquisition method is applied. SFAS 160 changes the accounting and reporting for minority interests, which are re-characterized as non-controlling interests, and classified as a component of equity. The Company adopted SFAS 141R and SFAS 160 on January 1, 2009. There was no impact on the Company s operating results, financial position or cash flows; however if the Company enters into future business combinations, certain transaction related expenses may be recorded within the Company s operating results which could reduce its current period net income or increase its net loss. Additionally, valuation of certain assets may be different than under the old accounting standards.

In September 2006, the FASB issued SFAS 157, *Fair Value Measurements* (SFAS 157), which defines fair value, establishes a framework for measuring fair value, and expands disclosures about fair value measurements. This pronouncement applies to other standards that require or permit fair value measurements. Accordingly, this statement does not require any new fair value measurements. The Company adopted the provisions of SFAS 157 on January 1, 2008. See Note 5 *Fair Value Measurements* for more details.

Effective January 1, 2009, the Company adopted FSP No. FAS 157-2, *Effective Date of FASB Statement No. 157* (FSP 157-2). FSP 157-2 delayed the effective date of SFAS 157 for all non-financial assets and non-financial liabilities, except for items that are recognized or disclosed at fair value in the financial statements on a recurring basis (at least annually), until the beginning of the first quarter of fiscal 2009. These include goodwill and other non-amortizable intangible assets as well as asset retirement obligations. The adoption of SFAS 157-2 did not have a significant impact on the Company s operating results, financial position or cash flows. See Note 6 *Asset Retirement Obligations* for more details.

In June 2008, the FASB issued Emerging Issues Task Force (EITF) 03-6-1, *Determining Whether Instruments Granted in Share-Based Payment Transactions Are Participating Securities* (EITF 03-6-1). EITF 03-6-1 clarifies that share-based payment awards that entitle their holders to receive non-forfeitable dividends or dividend equivalents before vesting should be considered participating securities. The adoption of EITF 03-6-1 on January 1, 2009 did not have a significant impact on the Company s operating results, financial position or cash flows.

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2. ACQUISITIONS AND DIVESTITURES

Acquisitions

Fayetteville Shale

On January 7, 2008, the Company entered into an agreement to purchase additional properties located in the Fayetteville Shale for $231.3 million after customary closing adjustments. The transaction closed on February 8, 2008. The acquired properties include interests primarily in Van Buren and Cleburne Counties, Arkansas that are substantially undeveloped.

Elm Grove Field

On January 22, 2008, the Company completed an acquisition of interests in the Elm Grove Field, located primarily in Bossier and Caddo Parishes of North Louisiana, for approximately $169 million.

Divestitures

Gulf Coast Properties

On November 30, 2007, the Company completed the sale of its Gulf Coast properties for $825 million, consisting of $700 million in cash and a $125 million note that the purchaser could redeem at any time prior to one year from November 30, 2007 for $100 million plus accrued and unpaid interest. If the redemption occurred prior to April 29, 2008, accrued interest would be waived. On April 28, 2008, the purchaser redeemed the note for $100 million.

3. OIL AND NATURAL GAS PROPERTIES

The Company uses the full cost method of accounting for its investment in oil and natural gas properties. Under this method of accounting, all costs of acquisition, exploration and development of oil and natural gas reserves (including such costs as leasehold acquisition costs, geological expenditures, dry hole costs, tangible and intangible development costs and direct internal costs) are capitalized as the cost of oil and natural gas properties when incurred. To the extent capitalized costs of evaluated oil and natural gas properties, net of accumulated depletion exceed the discounted future net revenues of proved oil and natural gas reserves net of deferred taxes, such excess capitalized costs are charged to expense. Full cost companies use the prices in effect at the end of each accounting quarter to calculate the ceiling test value of their reserves. Subsequent commodity price increases may be utilized to calculate the ceiling value and reserves. However, this option will no longer be available to the Company starting December 31, 2009 due to adoption of the new oil and natural gas reporting requirements.

The Company assesses all items classified as unevaluated property on a quarterly basis for possible impairment or reduction in value. The Company assesses properties on an individual basis or as a group if properties are individually insignificant. The assessment includes consideration of the following factors, among others: intent to drill; remaining lease term; geological and geophysical evaluations; drilling results and activity; the assignment of proved reserves; and the economic viability of development if proved reserves are assigned. During any period in which these factors indicate an impairment, the cumulative drilling costs incurred to date for such property and all or a portion of the associated leasehold costs are transferred to the full cost pool and are then subject to amortization.

At June 30, 2009, the ceiling test value of the Company s reserves was calculated based on the June 30, 2009 West Texas Intermediate (WTI) posted price of $69.89 per barrel, adjusted by lease for quality, transportation fees, and regional price differentials, and the June 30, 2009 Henry Hub spot market price of $3.89 per million British thermal units (Mmbtu), adjusted by lease for energy content, transportation fees, and regional price differentials. At June 30, 2009, the Company s net book value of oil and natural gas properties did not exceed the ceiling amount. Changes in production rates, levels of reserves, future development costs, and other factors will determine the Company s actual ceiling test calculation and impairment analyses in future periods.

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At March 31, 2009 the ceiling test value of the Company s reserves was calculated based on the March 31, 2009 WTI posted price of $49.66 per barrel, adjusted by lease for quality, transportation fees, and regional price differentials, and the March 31, 2009 Henry Hub spot market price of $3.63 per Mmbtu, adjusted by lease for energy content, transportation fees, and regional price differentials. Using these prices, the Company s net book value of oil and natural gas properties exceeded the ceiling amount by approximately $1.7 billion before tax, $1.1 billion after tax. Accordingly, the Company recorded an approximate $1.7 billion full cost ceiling impairment at March 31, 2009, before tax.

At December 31, 2008, the ceiling test value of the Company s reserves was calculated based on the December 31, 2008 WTI posted price of $41.00 per barrel, adjusted by lease for quality, transportation fees, and regional price differentials, and the December 31, 2008, Henry Hub spot market price of $5.71 per Mmbtu, adjusted by lease for energy content, transportation fees, and regional price differentials. At December 31, 2008, the Company s net book value of oil and natural gas properties exceeded the ceiling amount by approximately $1.0 billion before tax, and $574 million after tax. Accordingly, the Company recorded approximately $1.0 billion in full cost ceiling impairments at December 31, 2008, before tax.

4. LONG-TERM DEBT

Long-term debt as of June 30, 2009 and December 31, 2008 consisted of the following:

	June 30, 2009(1)	December 31, 2008(1)
	(In thousands)	
Senior revolving credit facility	$	$ 450,000
10.5% $600 million senior notes (2)	550,576	
7.875% $800 million senior notes	800,000	800,000
9.125% $775 million senior notes (3)	764,222	763,773
7.125% $275 million senior notes (4)	265,217	264,080
9.875% senior notes	224	254
Deferred premiums on derivatives	17,862	5,767
	$ 2,398,101	$ 2,283,874

(1) Amount excludes $35.2 million and $9.4 million of long-term debt which has been classified as current at June 30, 2009 and December 31, 2008, respectively. These amounts represent deferred premiums on derivatives contracts that are expected to be settled in the next 12 months.
(2) Amount includes a $49.4 million discount at June 30, 2009 recorded by the Company in conjunction with the issuance of the notes. See 10.5% Senior Notes below for more details.
(3) This amount is comprised of the $650.0 million and $125.0 million private placements consummated in July 2006. These amounts include a $5.4 million and $5.9 million discount at June 30, 2009 and December 31, 2008, respectively, recorded by the Company in conjunction with the issuance of the $650.0 million notes. Additionally, these amounts include a $0.9 and $1.0 million premium at June 30, 2009 and December 31, 2008, recorded by the Company in conjunction with the issuance of the $125.0 million notes. See 9.125% Senior Notes below for more details.
(4) Amount includes a $7.2 million and $8.3 million discount at June 30, 2009 and December 31, 2008, respectively, recorded by the Company in conjunction with the assumption of the notes. See 7.125% Senior Notes below for more details.

Senior Revolving Credit Facility

The Company entered into the Third Amended and Restated Senior Revolving Credit Agreement, dated as of September 10, 2008 (the Senior Credit Agreement), between the Company, each of the lenders from time to time party thereto (the Lenders), BNP Paribas, as administrative agent for the Lenders, Bank of America, N.A. and BMO Capital Markets Financing, Inc. as co-syndication agents for the Lenders, and JPMorgan Chase Bank,

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N.A., Wells Fargo Bank, N.A. and Fortis Capital Corp. as co-documentation agents for the Lenders, which amends and restates its $1 billion senior revolving credit agreement dated July 12, 2006. The Senior Credit Agreement provides for a $1.5 billion facility with a borrowing base of $1.1 billion that will be redetermined on a semi-annual basis, with the Company and the Lenders each having the right to one annual interim unscheduled redetermination, and adjusted based on the Company s oil and natural gas properties, reserves, other indebtedness and other relevant factors. The Company s borrowing base is subject to a reduction equal to the product of $0.25 multiplied by the stated principal amount (without regard to any initial issue discount) of any notes that the Company may issue. On January 27, 2009, the Company completed a private placement offering to eligible purchasers of an aggregate principal amount of $600 million 10.5% senior notes due August 1, 2014. In conjunction with the closing of this offering, the Company s borrowing base was reduced to $950 million. During the first quarter of 2009, the Company initiated a borrowing base redetermination under its Senior Credit Agreement. The Company s borrowing base of $950 million, along with its existing terms and pricing, were reaffirmed.

Amounts outstanding under the Senior Credit Agreement will bear interest at specified margins over the London Interbank Offered Rate (LIBOR) of 1.25% to 2.00% for Eurodollar loans or at specified margins over the Alternate Base Rate (ABR) of 0.00% to 0.50% for ABR loans. Such margins will fluctuate based on the utilization of the facility. Borrowings under the Senior Credit Agreement may be secured by first priority liens on substantially all of the Company s assets, including pursuant to the terms of the Third Amended and Restated Guarantee and Collateral Agreement, substantially all of the assets of, and all equity interests in, the Company s subsidiaries. Amounts drawn down on the facility will mature on July 1, 2013.

The Senior Credit Agreement contains financial and other covenants, including minimum working capital levels (the ratio of current assets plus the unused commitment under the Senior Credit Agreement to current liabilities) of not less than 1.0 to 1.0 and minimum coverage of interest expenses of not less than 2.5 to 1.0. In addition, the Company is subject to covenants limiting dividends and other restricted payments, transactions with affiliates, incurrence of debt, changes of control, asset sales, and liens on properties. At June 30, 2009, the Company was in compliance with all of its debt covenants under the Senior Credit Agreement.

10.5% Senior Notes

On January 27, 2009, the Company completed a private placement offering to eligible purchasers of an aggregate principal amount of $600 million principal amount of its 10.5% senior notes due August 1, 2014 (the 2014 Notes). The 2014 notes were issued under and are governed by an indenture dated January 27, 2009, between the Company, U.S. Bank Trust National Association, as trustee, and the Company s subsidiaries named therein as guarantors (the 2014 Indenture). The 2014 Notes were priced at 91.279% of the face value to yield 12.7% to maturity. Net proceeds from the offering were used to repay all outstanding borrowings on the Company s Senior Credit Agreement.

The 2014 Notes bear interest at a rate of 10.5% per annum, payable semi-annually on February 1 and August 1 of each year, commencing August 1, 2009. The 2014 notes will mature on August 1, 2014. The 2014 Notes are senior unsecured obligations of the Company and rank equally with all of its current and future senior indebtedness. The 2014 Notes are jointly and severally guaranteed on a senior unsecured basis by the Company s subsidiaries. Petrohawk Energy Corporation, the issuer of the Notes, has no material independent assets or operations apart from the assets and operations of its subsidiaries.

On or before February 1, 2012, the Company may redeem up to 35% of the aggregate principal amount of the 2014 Notes with the net cash proceeds of certain equity offerings at a redemption price of 110.5% of the principal amount plus accrued interest and unpaid interest to the redemption date provided that at least 65% in aggregate principal amount of the 2014 Notes originally issued under the 2014 Indenture remain outstanding immediately after the redemption. In addition, at any time prior to February 1, 2012, the Company may redeem some or all of the 2014 Notes for the principal amount thereof, plus accrued and unpaid interest plus a make whole premium equal to the excess, if any of (a) the present value at such time of (i) the redemption price of such note at February 1, 2012, (ii) plus required interest payments due on the notes, computed using a discount rate based upon the yield of U.S. Treasury securities with a constant maturity most nearly equal to the period from the redemption date to February 1, 2012 plus 50 basis points, over (b) the principal amount of such note.

On or after February 1, 2012, the Company may redeem some or all of the 2014 Notes at any time or from time to time at the redemption prices (expressed as a percentage of principal amount) set forth in the following table plus accrued and unpaid interest, if any, to the applicable redemption date, if redeemed during the 12-month period beginning February 1 of the years indicated below:

Year	**Percentage**
2012	110.500
2013	105.250
2014	100.000

The Company may be required to offer to repurchase the 2014 Notes at a purchase price of 101% of the principal amount, plus accrued and unpaid interest, if any, to the redemption date, in the event of a change of control as defined in the 2014 Indenture. The 2014 Indenture contains covenants that, among other things, restrict or limit the ability of the Company and its subsidiaries to: borrow money; pay dividends on stock; purchase or redeem stock or subordinated indebtedness; make investments; create liens; enter into transactions with affiliates; sell assets; and merge with or into other companies or transfer all or substantially all of the Company s assets. At June 30, 2009, the Company was in compliance with all of its debt covenants relating to the 2014 Notes.

In conjunction with the issuance of the $600 million 2014 Notes, the Company recorded a discount of $52.3 million to be amortized over the remaining life of the notes utilizing the effective interest rate method. The remaining unamortized discount was $49.4 million at June 30, 2009.

7.875% Senior Notes

On May 13, 2008 and June 19, 2008, the Company issued $500 million principal amount and $300 million principal amount, respectively, of its 7.875% senior notes due 2015 (the 2015 Notes). The 2015 Notes were issued under and are governed by an indenture dated May 13, 2008, between the Company, U.S. Bank Trust National Association, as trustee, and the Company s subsidiaries named therein as guarantors.

The 2015 Notes bear interest at a rate of 7.875% per annum, payable semi-annually on June 1 and December 1 of each year, commencing December 1, 2008. The 2015 Notes will mature on June 1, 2015. The 2015 Notes are senior unsecured obligations of the Company and rank equally with all of its current and future senior indebtedness. The 2015 Notes are jointly and severally guaranteed on a senior unsecured basis by the Company s subsidiaries. Petrohawk Energy Corporation, the issuer of the 2015 Notes, has no material independent assets or operations apart from the assets and operations of its subsidiaries. At June 30, 2009, the Company is in compliance with all of its debt covenants relating to the 2015 Notes.

9.125% Senior Notes

In July 2006, the Company consummated its private placement of 9.125% Senior Notes, also referred to as the 2013 Notes, pursuant to an Indenture dated as of July 12, 2006 (2013 Indenture) and the First Supplemental Indenture to the 2013 Notes (the 2013 First Supplemental Indenture), among the Company, the Company s subsidiaries named therein as guarantors, and U.S. Bank National Association, as trustee. The 2013 Notes were issued at 98.735% of the face amount.

The 2013 Notes bear interest at the rate of 9.125% per annum, payable semi-annually on January 15 and July 15 of each year, commencing January 15, 2007. The 2013 Notes mature on July 15, 2013. The 2013 Notes are senior unsecured obligations of the Company and rank equally with all of its current and future senior indebtedness, including the 2012 Notes. The 2013 Notes rank effectively subordinate to the Company s secured debt to the extent of the collateral, including secured debt under the Senior Credit Agreement, and senior to any future subordinated indebtedness. The 2013 Notes are jointly and severally guaranteed on a senior unsecured basis by the Company s subsidiaries, including, pursuant to the 2013 First Supplemental Indenture, the KCS Energy, Inc. (KCS) subsidiaries acquired in the Company s merger with KCS. Petrohawk Energy Corporation, the issuer of the 2013 Notes, has no material independent assets or operations apart from the assets and operations of its subsidiaries. At June 30, 2009, the Company was in compliance with all of its debt covenants relating to the 2013 Notes.

In conjunction with the issuance of the $650 million 2013 Notes, the Company recorded a discount of $8.2 million to be amortized over the remaining life of the notes utilizing the effective interest rate method. The remaining unamortized discount was $5.4 million at June 30, 2009. In conjunction with the issuance of the $125 million 2013 Notes, the Company recorded a premium of $1.4 million to be amortized over the remaining life of the notes utilizing the effective interest rate method. The remaining unamortized premium was $0.9 million at June 30, 2009.

7.125% Senior Notes

On July 12, 2006, the date of the Company s merger with KCS, the Company assumed (pursuant to the Second Supplemental Indenture relating to the 7.125% Senior Notes, also referred to as the 2012 Notes), and subsidiaries of the Company guaranteed (pursuant to the Third Supplemental Indenture relating to such notes), all the obligations (approximately $275 million) of KCS under the 2012 Notes and the Indenture dated April 1, 2004 (the 2012 Indenture) among KCS, U.S. Bank National Association, as trustee, and the subsidiary guarantors named therein, which governs the terms of the 2012 Notes. The 2012 Notes are guaranteed on an unsubordinated, unsecured basis by all of the Company s current subsidiaries, including the subsidiaries of KCS that the Company acquired in the merger. Interest on the 2012 Notes is payable semi-annually, on each April 1 and October 1. The 2012 Notes are jointly and severally guaranteed on a senior unsecured basis by the Company s subsidiaries. Petrohawk Energy Corporation, the issuer of the Notes, has no material independent assets or operations apart from the assets and operations of its subsidiaries. At June 30, 2009, the Company was in compliance with all of its debt covenants under the 7.125% Senior Notes.

In conjunction with the assumption of the 7.125% Senior Notes from KCS, the Company recorded a discount of $13.6 million to be amortized over the remaining life of the notes utilizing the effective interest rate method. The remaining unamortized discount is $7.2 million at June 30, 2009.

9.875% Senior Notes

On April 8, 2004, Mission Resources Corporation (Mission) issued $130.0 million of its 9.875% senior notes due 2011 (the 2011 Notes). The Company assumed these notes upon the closing of the Company s merger with Mission. In conjunction with the Company s merger with KCS, the Company extinguished substantially all of its 2011 Notes for a premium of $14.9 million plus accrued interest of $3.5 million. There were approximately $0.2 million of the notes which were not redeemed and are still outstanding as of June 30, 2009. In connection with the extinguishment of substantially all of the 2011 Notes, the Company requested and received from the noteholders consent to eliminate most significant debt covenants associated with the 2011 Notes.

Debt Issuance Costs

The Company capitalizes certain direct costs associated with the issuance of long-term debt. The Company capitalized $23.8 million of debt issue costs in connection with the Company s issuance of 2015 Notes in May and June 2008 and in connection with the Company s amended and restated senior revolving credit facility in September 2008. The Company capitalized $13.2 million with its issuance of the 2014 Notes in January 2009. In the first quarter of 2009, the Company wrote off $0.9 million of debt issuance costs as a result of the 2014 Notes issuance and from the reduction of our Senior Credit Agreement s borrowing base to $950 million. At June 30, 2009 and December 31, 2008, the Company had approximately $38.8 million and $30.5 million, respectively of debt issuance costs remaining that are being amortized over the lives of the respective debt.

5. FAIR VALUE MEASUREMENTS

Effective January 1, 2008, the Company adopted SFAS 157. SFAS 157 defines fair value, establishes a framework for measuring fair value and expands the related disclosure requirements. Pursuant to SFAS 157, the Company s determination of fair value incorporates not only the credit standing of the counterparties involved in transactions with the Company resulting in receivables on the Company s condensed consolidated balance sheets, but also the impact of the Company s nonperformance risk on its liabilities.

SFAS 157 defines fair value as 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 Company utilizes market data or assumptions that market participants 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 classifies fair value balances based on the observability of those inputs. SFAS 157 establishes a fair value hierarchy that prioritizes the inputs used to measure fair value. The hierarchy gives the highest priority to unadjusted quoted prices in active markets for identical assets or liabilities (level 1 measurement) and the lowest priority to unobservable inputs (level 3 measurement).

The three levels of the fair value hierarchy defined by SFAS 157 are as follows:

Level 1 Quoted prices are available in active markets for identical assets or liabilities as of the reporting date. Active markets are those in which transactions for the asset or liability occur in sufficient frequency and volume to provide pricing information on an ongoing basis. Level 1 primarily consists of financial instruments such as exchange-traded derivatives, marketable securities and listed equities.

Level 2 Pricing inputs are other than quoted prices in active markets included in level 1, which are either directly or indirectly observable as of the reported date. Level 2 includes those financial instruments that are valued using models or other valuation methodologies. These models are primarily industry-standard models that consider various assumptions, including quoted forward prices for commodities, time value, volatility factors, and current market and contractual prices for the underlying instruments, as well as other relevant economic measures. Substantially all of these assumptions are observable in the marketplace throughout the full term of the instrument, can be derived from observable data or are supported by observable levels at which transactions are executed in the marketplace. Instruments in this category generally include non-exchange-traded derivatives such as commodity swaps, interest rate swaps, options and collars.

Level 3 Pricing inputs include significant inputs that are generally less observable from objective sources. These inputs may be used with internally developed methodologies that result in management s best estimate of fair value.

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The following tables set forth by level within the fair value hierarchy the Company s financial assets and liabilities that were accounted for at fair value as of June 30, 2009 and December 31, 2008. As required by SFAS 157, a financial instrument s level within the fair value hierarchy is based on the lowest level of input that is significant to the fair value measurement. The Company s assessment of the significance of a particular input to the fair value measurement requires judgment, and may affect the valuation of fair value assets and liabilities and their placement within the fair value hierarchy levels.

	June 30, 2009			
	Level 1	Level 2	Level 3	Total
		(In thousands)		
Assets:				
Marketable securities	$ 17,020	$	$	$ 17,020
Receivables from derivative contracts		289,065		289,065
	$ 17,020	$ 289,065	$	$ 306,085
Liabilities:				
Liabilities from derivative contracts	$	$ 3,076	$	$ 3,076
	$	$ 3,076	$	$ 3,076

	December 31, 2008			
	Level 1	Level 2	Level 3	Total
		(In thousands)		
Assets:				
Marketable securities	$ 123,009	$	$	$ 123,009
Receivables from derivative contracts		224,527		224,527
	$ 123,009	$ 224,527	$	$ 347,536
Liabilities:				
Liabilities from derivative contracts	$	$	$	$
	$	$	$	$

Marketable securities listed above are carried at fair value. The Company is able to value its marketable securities based on quoted fair values for identical instruments, which resulted in the Company reporting its marketable securities as Level 1.

Derivatives listed above include collars, swaps, basis swaps and puts that are carried at fair value. The Company records the net change in the fair value of these positions in *Net gain (loss) on derivative contracts* in the Company s condensed consolidated statements of operations. The Company is able to value the assets and liabilities based on observable market data for similar instruments, which resulted in the Company reporting its derivatives as Level 2. This observable data includes the forward curve for commodity prices based on quoted markets prices and prospective volatility factors related to changes in the forward curves.

As of June 30, 2009 and December 31, 2008, the Company s derivative contracts were with major financial institutions with investment grade credit ratings which are believed to have a minimal credit risk. As such, the Company is exposed to credit risk to the extent of nonperformance by the counterparties in the derivative contracts discussed above; however, the Company does not anticipate such nonperformance. Each of the counterparties to the Company s derivative contracts is a lender in the Company s Senior Credit Agreement. The Company did not post collateral under any of these contracts as they are secured under the Senior Credit Agreement.

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The following disclosure of the estimated fair value of financial instruments is made in accordance with the requirements of FAS 107-1. The estimated fair value amounts have been determined at discrete points in time based on relevant market information. These estimates involve uncertainties and cannot be determined with precision. The estimated fair value of cash, accounts receivable and accounts payable approximates their carrying value due to their short-term nature. The estimated fair value of the Company s Senior Credit Agreement approximates carrying value because the facility s interest rate approximates current market rates. The following table presents the estimated fair values of the Company s fixed interest rate debt instruments as of June 30, 2009 and December 31, 2008 (excluding premiums and discounts):

	June 30, 2009		December 31, 2008	
Debt	**Carrying Amount**	**Estimated Fair Value**	**Carrying Amount**	**Estimated Fair Value**
		(In thousands)		
10.5% $600 million senior notes	$ 600,000	$ 612,750	$	$
7.875% $800 million senior notes	800,000	740,000	800,000	591,040
9.125% $775 million senior notes	768,725	765,842	768,725	595,762
7.125% $275 million senior notes	272,375	256,033	272,375	223,348
9.875% senior notes	224	225	254	213
	$ 2,441,324	$ 2,374,850	$ 1,841,354	$ 1,410,363

6. ASSET RETIREMENT OBLIGATIONS

The Company records an asset retirement obligation (ARO) when the total depth of a drilled well is reached and the Company can reasonably estimate the fair value of an obligation to perform site reclamation, dismantle facilities or plug and abandon costs. For gas gathering systems, the Company records an ARO when the system is placed in service and the Company can reasonably estimate the fair value of an obligation to perform site reclamation and other necessary work. The Company records the ARO liability on the condensed consolidated balance sheets and capitalizes a portion of the cost in O*il and natural gas properties evaluated* or *Gas gathering system and equipment* during the period in which the obligation is incurred. In general, the amount of an ARO and the costs capitalized will be equal to the estimated future cost to satisfy the abandonment obligation using current prices that are escalated by an assumed inflation factor up to the estimated settlement date and adjusted for the Company s credit risk. This amount is then discounted back to the date that the abandonment obligation was incurred using an assumed cost of funds for the Company. After recording these amounts, the ARO is accreted to its future estimated value using the same assumed cost of funds. The Company records the accretion of its ARO liabilities in *Depletion, depreciation and amortization* expense in the condensed consolidated statements of operations. The additional capitalized costs are depreciated on a unit-of-production basis or straight-line basis.

The Company recorded the following activity related to its ARO liability for the six months ended June 30, 2009 (in thousands):

Liability for asset retirement obligation as of December 31, 2008	$ 28,644
Liabilities settled and divested	(307)
Additions	1,190
Accretion expense	700
Liability for asset retirement obligation as of June 30, 2009	$ 30,227

7. COMMITMENTS AND CONTINGENCIES

From time to time, the Company may be a plaintiff or defendant in a pending or threatened legal proceeding arising in the normal course of its business. All known liabilities are accrued based on the Company s best estimate of the potential loss. While the outcome and impact of currently pending legal proceedings cannot be predicted with certainty, the Company s management and legal counsel believe that the resolution of these proceedings through settlement or adverse judgment will not have a material adverse effect on the Company s condensed consolidated operating results, financial position or cash flows. Please refer to Part II. Other Information, Item 1. Legal Proceedings for further information on pending cases.

As of June 30, 2009, the Company has drilling rigs under contract with a total commitment of $355.1 million over four years. At December 31, 2008, the Company had drilling rigs under contract with a total commitment of $433.0 million over four years.

The Company has various other contractual commitments pertaining to exploration, development and production activities. The Company has work related commitments for, among other things, pipeline and well equipment, obtaining and processing seismic data and natural gas pipeline transportation. At June 30, 2009 and December 31, 2008, these work related commitments totaled $1.1 billion over 16 years and $507.8 million over 20 years, respectively.

8. DERIVATIVES

The Company is exposed to certain risks relating to its ongoing business operations, such as commodity price risk and interest rate risk. Derivative contracts are utilized to economically hedge its exposure to price fluctuations and reduce the variability in the Company s cash flows associated with anticipated sales on future oil and natural gas production. The Company generally hedges a substantial, but varying, portion of anticipated oil and natural gas production for the next 12-36 months. Derivatives are carried at fair value on the condensed consolidated balance sheets, with the changes in the fair value included in the condensed consolidated statements of operations for the period in which the change occurs. Generally, the Company enters into interest rate swaps to mitigate exposure to market rate fluctuations by converting variable interest rates (such as those on the Company s Senior Credit Agreement) to fixed interest rates.

It is the Company s policy to enter into derivative contracts, including interest rate swaps, only with counterparties that are creditworthy financial institutions deemed by management as competent and competitive market makers. Each of the counterparties to the Company s derivative contracts is a lender in the Company s Senior Credit Agreement. The Company did not post collateral under any of these contracts as they are secured under the Company s Senior Credit Agreement.

At June 30, 2009 the Company has entered into commodity collars, swaps, put options and basis swaps. The Company has elected to not designate any of its derivative contracts for hedge accounting. Accordingly, the Company records the net change in the mark-to-market valuation of these derivative contracts, as well as all payments and receipts on settled derivative contracts, in *Net gain (loss) on derivatives contracts* on the condensed consolidated statements of operations.

During the second quarter of 2009, the Company entered into interest rate swaps to convert a portion of its long-term debt from a fixed interest rate to a variable interest rate. At June 30, 2009 the Company had five open interest rate swap positions that converted its $600 million senior notes with a 10.5% fixed interest rate to a variable interest rate with a fixed spread ranging from 1.50% to 1.55% against LIBOR for the next two years.

During the first quarter of 2009, the Company entered into three interest rate swap derivative contracts. In conjunction with the issuance of the 2014 Notes in January 2009, the Company repaid all outstanding borrowings under its Senior Credit Agreement. As a result, the Company made the decision to settle all of its outstanding interest rate swap derivative contracts which resulted in a minimal gain during the first quarter of 2009. This gain is included in *Net gain (loss) on derivative contracts* on the condensed consolidated statements of operations.

During the first quarter of 2008, the Company entered into two interest rate swap derivative contracts. In conjunction with the Company s debt and equity raises during the second quarter of 2008, the Company repaid

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all outstanding borrowings under its Senior Credit Agreement. As a result, the Company made the decision to settle all of its outstanding interest rate swap derivative contracts which resulted in a gain of $1.5 million during the second quarter of 2008 which is included in *Net gain (loss) on derivative contracts* on the condensed consolidated statements of operations.

At June 30, 2009, the Company had 109 open commodity derivative contracts summarized in the tables below: 86 natural gas collar arrangements, two natural gas swap arrangements, two natural gas basis swap arrangement, 15 natural gas put options and four crude oil price swap arrangements. Derivative commodity contracts settle based on NYMEX West Texas Intermediate and Henry Hub prices which may differ from the actual price received by the Company for the sale of its oil and natural gas production. The Company s basis swaps hedge the basis differential between NYMEX Henry Hub price and the Houston Ship Channel price.

At December 31, 2008, the Company had 69 open commodity derivative contracts summarized in the tables below: 52 natural gas collar arrangements, two natural gas swap arrangements, one natural gas basis swap arrangement, 10 natural gas put options and four crude oil price swap arrangements.

All derivative contracts are recorded at fair market value in accordance with SFAS 157 and included in the condensed consolidated balance sheets as assets or liabilities. The following table summarizes the location and fair value amounts of all derivative contracts in the condensed consolidated balance sheets as of June 30, 2009 and December 31, 2008:

Derivatives not designated as hedging contracts under SFAS 133	**Asset derivative contracts**			**Liability derivative contracts**		
	Balance sheet location	**June 30, 2009**	**December 31, 2008**	**Balance sheet location**	**June 30, 2009**	**December 31, 2008**
		(In thousands)			**(In thousands)**	
Commodity contracts	Current assets - receivables from derivative contracts	$ 234,687	$ 201,128	Current liabilities - liabilities from derivative contracts	$ (357)	$
Commodity contracts	Other noncurrent assets - receivables from derivative contracts	49,507	23,399	Other noncurrent liabilities - liabilities from derivative contracts	(127)	
Interest rate contracts	Current assets - receivables from derivative contracts	4,871		Current liabilities - liabilities from derivative contracts		
Interest rate contracts	Other noncurrent assets - receivables from derivative contracts			Other noncurrent liabilities - liabilities from derivative contracts	(2,592)	
Total derivatives not designated as hedging contracts under SFAS 133		$ 289,065	$ 224,527		$ (3,076)	$

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The following table summarizes the location and amounts of the Company s realized and unrealized gains and losses on derivative contracts recognized in other (expenses) income in the Company s condensed consolidated statements of operations:

Derivatives not designated as hedging contracts under SFAS 133	Location of gain or (loss) recognized in income on derivative contracts	Amount of gain or (loss) recognized in income on derivative contracts three months ended June 30, 2009 (In thousands)	2008	Amount of gain or (loss) recognized in income on derivative contracts six months ended June 30, 2009 (In thousands)	2008
Commodity contracts:					
Unrealized (loss) gain on commodity contracts	Other (expenses) income - net gain (loss) on derivative contracts	$ (84,626)	$ (229,908)	$ 16,139	$ (366,580)
Realized gain (loss) on commodity contracts	Other (expenses) income - net gain (loss) on derivative contracts	98,074	(50,040)	179,221	(55,266)
Total net gain (loss) on commodity contracts		$ 13,448	$ (279,948)	$ 195,360	$ (421,846)
Interest rate swaps:					
Unrealized gain on interest rate swaps	Other (expenses) income - net gain (loss) on derivative contracts	$ 2,280	$ 843	$ 2,280	$
Realized gain on interest rate swaps	Other (expenses) income - net gain (loss) on derivative contracts	278	1,500	288	1,500
Total net gain on interest rate swaps		$ 2,558	$ 2,343	$ 2,568	$ 1,500
Total net gain (loss) on derivative contracts	Other (expenses) income - net gain (loss) on derivative contracts	$ 16,006	$ (277,605)	$ 197,928	$ (420,346)

At June 30, 2009 and December 31, 2008, the Company had the following open derivative contracts:

				June 30, 2009 Floors		Ceilings	
Period	Instrument	Commodity	Volume in Mmbtu s	Price / Price Range	Weighted Average Price	Price / Price Range	Weighted Average Price
July 2009 - December 2009 (1)	Collars	Natural gas	38,640,000	$ 4.50 - $9.00	$ 7.43	$ 6.69 - $16.45	$ 11.75
July 2009 - December 2009	Swaps	Natural gas	920,000	8.43	8.43		
July 2009 - December 2009	Floor	Natural gas	21,160,000	4.50 - 10.00	6.58		
July 2009 - December 2009	Swaps	Oil	138,000	76.85 - 77.30	77.00		
January 2010 - December 2010	Collars	Natural gas	138,700,000	5.00 - 7.00	5.97	9.00 - 10.00	9.21
January 2010 - December 2010	Swaps	Natural gas	1,825,000	8.22	8.22		
January 2010 - December 2010	Floor	Natural gas	7,240,000	4.49 - 4.55	4.54		
January 2010 - December 2010	Swaps	Oil	273,750	75.15 - 75.55	75.28		
January 2011 - December 2011	Collars	Natural gas	118,625,000	5.50 - 5.75	5.54	10.00 - 10.30	10.06

(1) Includes a natural gas collar with a second put option sold at $3.00 for 920,000 Mmbtus during the fourth quarter.

				June 30, 2009	
Period	Instrument	Commodity	Volume in Mmbtu s	Price Range	Weighted Average Price

July 2009 - December 2009	Basis swaps	Natural gas	3,680,000	$ 0.33 - $0.34	$	0.34

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Period	Instrument	Notional Amount	Variable Rate	Fix Rate Range	Weighted Average Fix Rate
		June 30, 2009			
July 2009 - June 2011	Interest rate contracts	$ 600,000,000	1 Month LIBOR	1.50% - 1.55%	1.52%

				December 31, 2008			
				Floors		Ceilings	
Period	Instrument	Commodity	Volume in Mmbtu s	Price / Price Range	Weighted Average Price	Price / Price Range	Weighted Average Price
January 2009 - December 2009	Collars	Natural gas	75,730,000	$ 7.00 - $10.00	$ 7.57	$ 9.60 - $16.45	$ 11.79
January 2009 - December 2009	Swaps	Natural gas	1,825,000	8.43	8.43		
January 2009 - December 2009	Floor	Natural gas	14,600,000	10.00	10.00		
January 2009 - December 2009	Swaps	Oil	273,750	76.85 - 77.30	77.00		
January 2010 - December 2010	Collars	Natural gas	29,200,000	7.00	7.00	10.00	10.00
January 2010 - December 2010	Swaps	Natural gas	1,825,000	8.22	8.22		
January 2010 - December 2010	Swaps	Oil	273,750	75.15 - 75.55	75.28		

			December 31, 2008		
Period	Instrument	Commodity	Volume in Mmbtu s	Price / Price Range	Weighted Average Price
January 2009 - December 2009	Basis swaps	Natural gas	3,650,000	$ 0.33	$ 0.33

9. STOCKHOLDERS EQUITY

At the Company s annual meeting on June 18, 2009, its shareholders voted on three proposals related to its common stock and stock plans. The Company s Certificate of Incorporation was amended to increase the number of shares of common stock available for issuance from 300 million shares to 500 million shares. In addition, amendments to the Company s 2004 Employee Incentive Plan and the 2004 Non-Employee Director Incentive Plan were ratified and approved to increase the number of shares of common stock that may be issued under the plans by 5.3 million shares and 0.5 million shares, respectively.

On March 4, 2009, the Company sold an aggregate of 22 million shares of its common stock in an underwritten public offering. The gross proceeds from the sale were approximately $385 million, before deducting underwriting discounts and commissions and estimated expenses of $9 million.

On August 15, 2008, the Company sold an aggregate of 28.8 million shares of its common stock in an underwritten public offering. The gross proceeds from the sale were approximately $763 million, before deducting underwriting discounts and commissions and estimated expenses of $29 million.

On May 13, 2008, the Company sold an aggregate of 25.0 million shares of its common stock in an underwritten public offering. Pursuant to the underwriting agreement, the Company granted the underwriters a 30-day option to purchase up to an additional 3.75 million shares of common stock at the public offering price less underwriting discounts and commissions. The underwriters exercised in full their option to purchase additional shares of common stock which closed on May 23, 2008. The gross proceeds from these sales were approximately $759 million, before deducting underwriting discounts and commissions and estimated expenses of $32 million.

On February 1, 2008, the Company sold an aggregate of 20.7 million shares of its common stock in an underwritten public offering. The gross proceeds from the sale were approximately $311 million, before deducting underwriting discounts and commissions and estimated expenses of $14 million.

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Warrants, Options and Stock Appreciation Rights

During the six months ended June 30, 2009, the Company granted stock options covering 1.5 million shares of common stock to employees of the Company. The stock options have exercise prices ranging from $15.23 to $26.12 with a weighted average price of $15.36. These awards vest over a three year period at a rate of one-third on the annual anniversary date of the grant and expire ten years from the grant date. At June 30, 2009, the unrecognized compensation expense related to non-vested stock appreciation rights and stock options totaled $10.5 million and will be recognized on a straight line basis over the weighted average remaining vesting period of 1.3 years.

During the six months ended June 30, 2008, the Company granted stock options covering 1.0 million shares of common stock to employees of the Company. The stock options have exercise prices ranging from $15.97 to $36.45 with a weighted average price of $18.30. These awards vest over a three year period at a rate of one-third on the annual anniversary date of the grant and expire ten years from the grant date.

During the six months ended June 30, 2009, there were 0.6 million warrants exercised at a price of $3.30 per share which represented the remaining outstanding warrants granted in conjunction with the recapitalization of the Company by PHAWK, LLC transaction in the second quarter of 2004.

Restricted Stock

During the six months ended June 30, 2009, the Company granted 0.6 million shares of restricted stock to employees of the Company and non-employee directors. These restricted shares were granted at prices ranging from $15.23 to $26.12 with a weighted average price of $15.40. Employee shares vest over a three-year period at a rate of one-third on the annual anniversary date of the grant and the non-employee directors shares vest six-months from the date of grant. At June 30, 2009, the unrecognized compensation expense related to non-vested restricted stock totaled $12.4 million and was to be recognized on a straight line basis over the weighted average remaining vesting period of 1.3 years.

During the six months ended June 30, 2008, the Company granted 0.5 million shares of restricted stock to employees of the Company. These restricted shares were granted at prices ranging from $15.97 to $46.31 with a weighted average price of $18.38. Employee shares vest over a three-year period at a rate of one-third on the annual anniversary date of the grant and the non-employee directors shares vest six-months from the date of grant.

Performance Shares

At December 31, 2008, the performance period related to the plan assumed in the merger between KCS and Petrohawk was completed. The required objectives were met and therefore a total of 0.2 million shares were issued on February 16, 2009. The shares are now held as restricted stock until the restriction lapses on December 31, 2009. The Company recognized $0.2 million in compensation cost for the six months ended June 30, 2008.

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Assumptions

The assumptions used in calculating the fair value of the Company s stock-based compensation are disclosed in the following table:

	Six Months Ended June 30, 2009	Six Months Ended June 30, 2008
Weighted average value per option granted during the period	$ 7.18	$ 5.35
Assumptions (1) (2) (3):		
Stock price volatility	70.0%	40.0%
Risk free rate of return	1.49%	1.97%
Expected term	3.0 years	3.0 years

(1) The Company s estimated future forfeiture is approximately 5% based on the Company s historical forfeiture rate.
(2) Calculated using the Black-Scholes fair value based method.
(3) The Company does not pay dividends on its common stock.

10. EARNINGS PER SHARE OF COMMON STOCK

The following represents the calculation of earnings per share of common stock:

	Three Months Ended June 30, 2009	Three Months Ended June 30, 2008	Six Months Ended June 30, 2009	Six Months Ended June 30, 2008
	(In thousands, except per share amounts)			
Basic				
Net loss	$ (22,004)	$ (92,766)	$ (1,021,757)	$ (148,378)
Weighted average basic number of shares outstanding	274,146	206,490	266,145	195,060
Basic net loss per share of common stock	$ (0.08)	$ (0.45)	$ (3.84)	$ (0.76)
Diluted				
Net loss	$ (22,004)	$ (92,766)	$ (1,021,757)	$ (148,378)
Weighted average basic number of shares outstanding	274,146	206,490	266,145	195,060
Common stock equivalent shares representing shares issuable upon exercise of stock options and stock appreciation rights	Anti-dilutive	Anti-dilutive	Anti-dilutive	Anti-dilutive
Common stock equivalent shares representing shares issuable upon exercise of warrants	Anti-dilutive	Anti-dilutive	Anti-dilutive	Anti-dilutive
Common stock equivalent shares representing shares included upon vesting of restricted shares	Anti-dilutive	Anti-dilutive	Anti-dilutive	Anti-dilutive
Weighted average diluted number of shares outstanding	274,146	206,490	266,145	195,060
Diluted net loss per share of common stock	$ (0.08)	$ (0.45)	$ (3.84)	$ (0.76)

Weighted average common stock equivalents, including stock options, SARS and warrants, totaling 2.7 million and 2.6 million shares were not included in the computations of diluted earnings per share because the effect would have been anti-dilutive due to the net loss for the three and six months ended June 30, 2009. Weighted average common stock equivalents of 4.2 million and 3.9 million shares were not included in the computations of diluted earnings per share because the effect would have been anti-dilutive due to the net loss for the three and six months ended June 30, 2008.

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11. ADDITIONAL FINANCIAL STATEMENT INFORMATION

Certain balance sheet amounts are comprised of the following:

	June 30, 2009	December 31, 2008
	(In thousands)	
Accounts receivable:		
Oil and gas revenues	$ 63,175	$ 98,536
Marketing revenues	21,648	36,476
Joint interest accounts	68,581	96,485
Income taxes receivable	12,718	35,535
Other	4,886	10,317
	$ 171,008	$ 277,349
Prepaids and other:		
Prepaid insurance	$ 2,055	$ 2,315
Prepaid drilling costs	46,920	35,739
Other	2,986	2,009
	$ 51,961	$ 40,063
Accounts payable and accrued liabilities:		
Trade payables	$ 44,514	$ 82,028
Revenues and royalties payable	126,412	145,828
Accrued capital costs	180,844	264,888
Accrued interest expense	69,475	42,548
Prepayment liabilities	40,108	59,234
Accrued lease operating expenses	6,639	7,017
Accrued ad valorem taxes payable	5,724	4,029
Accrued employee compensation	10,500	11,723
Income taxes payable	4,675	4,022
Other	29,762	18,115
	$ 518,653	$ 639,432

12. SUBSEQUENT EVENTS

On August 4, 2009, the Company announced its intention to raise capital through an equity offering. Proceeds from this offering are intended to provide the Company with additional financial flexibility to fund the capital budget, fund potential acquisitions and be used to pay down the outstanding borrowings under the senior revolving credit facility.

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

The following discussion of operations for the three and six months ended June 30, 2009 and 2008 should be read in conjunction with our condensed consolidated financial statements and the notes thereto included in this Form 10-Q and with the consolidated financial statements, notes and management s discussion and analysis included in our Annual Report on Form 10-K, as amended, for the year ended December 31, 2008.

Overview

We are an independent energy company engaged in the exploration, development and production of predominately natural gas properties located onshore in the United States. Our properties are primarily located in Louisiana, Texas, Arkansas and Oklahoma. We organize our operations into two principal regions: the Mid-Continent, which includes our Louisiana and Arkansas properties; and the Western, which includes our Texas and Oklahoma properties.

Historically, we have grown through acquisitions of proved reserves and undeveloped acreage, with a focus on properties within our core operating areas which we believe have significant development and exploration opportunities and where we can apply our technical experience and economies of scale to increase production and proved reserves while lowering lease operating costs. During 2008 and the first half of 2009, we have significantly expanded our leasehold position in natural gas shale plays, particularly in the Haynesville Shale play in northern Louisiana and East Texas and the Eagle Ford Shale play in South Texas. We currently own leasehold interests in approximately 325,000 net acres in the Haynesville Shale play, 157,000 net acres in the Fayetteville Shale play in Arkansas, and 210,000 net acres in the Eagle Ford Shale play. The vast majority of our acreage in these plays is currently undeveloped. Typically, the leases we own require that production in paying quantities be established on units under the lease within the lease term (generally three to five years) or the lease will expire, although a significant percentage of the leases in the Haynesville Shale play are currently held by production from other producing zones. Lease expirations will be an important factor determining our capital expenditures focus over the next several years.

Production increased 65% in the first six months of 2009 which averaged 448 million cubic feet of natural gas equivalent per day (Mmcfe/d) compared to average production of 272 Mmcfe/d during the first six months of 2008. The increase in production compared to prior year is driven by our drilling successes in the Haynesville, Fayetteville and Eagle Ford Shales. Overall, we drilled 297 gross wells (75.2 net wells) of which 296 gross (74.9 net) were successful resulting in a success rate of 99%.

Our financial results depend upon many factors, but are largely driven by the volume of our oil and natural gas production and the price that we receive for that production. Our production volumes will decline as reserves are depleted unless we expend capital in successful development and exploration activities or acquire properties with existing production. The amount we realize for our production depends predominantly upon commodity prices and our related commodity price hedging activities, which are affected by changes in market demand and supply, as impacted by overall economic activity, weather, pipeline capacity constraints, inventory storage levels, basis differentials and other factors. Accordingly, finding and developing oil and natural gas reserves at economical costs is critical to our long-term success.

During the second half 2008 and continuing to date in 2009, natural gas prices have declined significantly and have remained at lower levels due to the turmoil in the global financial system and the global economic recession negatively impacting demand. In response to declining natural gas prices we have focused our 2009 capital budget on the development of non-proved locations in our Haynesville, Fayetteville and Eagle Ford Shale plays. We believe these projects also offer the potential for high internal rates of return and reserve growth. Our 2009 capital budget is $1.3 billion, exclusive of acquisitions and focuses on three primary initiatives: 1) an increase in the rig count in the Haynesville Shale by year-end 2009, providing us the ability to secure more leasehold during a year in which our production is substantially hedged; 2) infrastructure expansion in the

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Haynesville Shale, based on successful drilling in new areas, gathering pipeline and facilities planned for construction in the Haynesville Shale during 2009, and 3) increased drilling activities of other operators, primarily in the Fayetteville Shale. Our future drilling plans are subject to change based upon various factors, some of which are beyond our control, including drilling results, natural gas prices, the availability and cost of capital, drilling and production costs, availability of drilling services and equipment, gathering system and pipeline transportation constraints and regulatory approvals. To the extent these factors lead to reductions in our drilling plans and associated capital budgets in future periods, our financial position, cash flows and operating results could be adversely impacted.

One consequence of continued low natural gas prices is the possibility that we may be required to recognize additional non-cash impairment expense under the full cost method of accounting, which we use to account for our oil and natural gas exploration and development activities. We recorded full cost ceiling impairments before income taxes of approximately $1.7 billion and $1.0 billion at March 31, 2009 and December 31, 2008, respectively, primarily due to the decrease in the Henry Hub spot market price to $3.63 from $5.71 per million British thermal units (Mmbtu). No impairment was required at June 30, 2009 as the Henry Hub spot market price increased to $3.89. If natural gas prices continue to decline, we may be required to take additional impairment charges in the future. If the WTI posted price and Henry Hub spot market price had been 10% lower while all other factors remained constant, the Company s ceiling amount related to its net book value of oil and natural gas properties would have been reduced by approximately $300 million resulting in a ceiling test impairment of approximately $136 million, before income taxes. Changes in production rates, levels of reserves, future development costs, and other factors will determine the Company s actual ceiling test calculation and impairment analyses in future periods.

On August 4, 2009, we announced our intention to raise approximately $583 million through a public equity offering. We intend to use the net proceeds to fund potential acquisitions, a portion of our capital budget and general corporate purposes including repayment of borrowings under our senior revolving credit facility.

Capital Resources and Liquidity

Our primary sources of capital resources and liquidity are internally generated cash flows from operations, availability under our Senior Credit Agreement, and access to capital markets, to the extent available. The capital markets have been adversely impacted by the current financial crisis, concerns about overall deflation and its effect on commodity prices, the possibility of a deepening world recession that could extend for a long period into the future, and a generally higher cost of capital. Continued volatility in the capital markets could adversely impact our access to capital, which could reduce our ability to execute our development and acquisition plans, our ability to replace our reserves, and eventually, our production levels. In February 2009, we initiated a borrowing base redetermination under our Senior Credit Agreement. Our borrowing base of $950 million, along with our existing terms and pricing were reaffirmed. We continue to monitor our liquidity and the capital markets.

Our 2009 capital budget, which includes drilling, completions, seismic and facilities, is currently $1.3 billion. The allocation of capital reflects an increased emphasis on development of non-proved locations in our Haynesville, Fayetteville and Eagle Ford Shale projects as well as the continued development of our Hawk Field Services business. Our Haynesville Shale capital budget for 2009 is heavily weighted towards drilling and completion activities to fulfill our drilling obligations associated with various lease terms. We continuously evaluate our development plans in light of a variety of factors, including, but not limited to, our cash flows, capital resources and drilling success. Our weighting in this regard and the effect this may have on our development of proved undeveloped reserves can, and likely will, change.

Our future capital resources and liquidity may depend, in part, on our success in developing the leasehold interests that we acquired. Cash is required to fund capital expenditures necessary to offset inherent declines in production and proven reserves, which is typical in the capital-intensive oil and gas industry. Future success in

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growing reserves and production will be highly dependent on our capital resources and our success in finding additional reserves. During 2008 and to date in 2009, we have raised $1.3 billion of debt (net of discounts and expenses) and $2.1 billion of equity capital (net of discounts and expenses). We expect to fund our future capital requirements through internally generated cash flows and borrowings under our Senior Credit Agreement, which gives us $950 million of borrowing capacity as of June 30, 2009, and through accessing the capital markets and pursuing asset monetization transactions when we consider market conditions favorable. Our ability to utilize the full amount of our borrowing capacity is influenced by a variety of factors, including semi-annual redeterminations of our borrowing base, which may also be redetermined periodically at the discretion of the banks, and covenants under our Senior Credit Agreement and our senior unsecured debt indentures limit the aggregate debt we may incur based upon the ratio of our adjusted consolidated earnings before interest, income taxes, depreciation, depletion and amortization and certain other non-cash charges (EBITDA), to our adjusted consolidated interest expense for the preceding four fiscal quarters and which may limit borrowings to a fixed percentage of our adjusted consolidated net tangible assets. Our borrowing base, EBITDA and consolidated net tangible assets are significantly influenced by, among other things, oil and natural gas prices. We strive to maintain financial flexibility while continuing our rapid growth and may access the capital markets to, among other things, maintain substantial borrowing capacity under our Senior Credit Agreement, facilitate drilling on our large undeveloped acreage position and permit us to selectively expand our acreage position and infrastructure projects. Our ability to complete future debt and equity offerings is limited by general market conditions.

Our long-term cash flows are subject to a number of variables including our level of production and commodity prices, as well as various economic conditions that have historically affected the oil and natural gas industry. If oil and natural gas prices remain at their current levels for a prolonged period of time or if natural gas prices continue to decline, our ability to fund our capital expenditures, reduce debt, meet our financial obligations and become profitable may be materially impacted.

On August 4, 2009, we announced our intent to raise approximately $583 million through a public equity offering. We intend to use the net proceeds to fund potential acquisitions, a portion of our capital budget and general corporate purposes including repayment of borrowings under our senior revolving credit facility.

Cash Flow

Our primary sources of cash for the six months ended June 30, 2009 and 2008 were from operating and financing activities. Proceeds from the sale of common stock, the issuance of new senior debt and cash received from operations were offset by repayments of our Senior Credit Agreement and cash used in investing activities to fund our drilling program and acquisition activities. Operating cash flow fluctuations were substantially driven by changes in commodity prices and changes in our production volumes. Working capital was substantially influenced by these variables. Fluctuation in cash flow may result in an increase or decrease in our future capital expenditures. Prices for oil and natural gas have historically been subject to seasonal influences typically characterized by peak demand and higher prices in the winter heating season; however, the impact of other risks and uncertainties have influenced prices throughout recent years. See Results of Operations below for a review of the impact of prices and volumes on revenues.

Net decrease in cash is summarized as follows:

	Six Months Ended June 30,	
	2009	**2008**
	(In thousands)	
Cash flows provided by operating activities	$ 326,116	$ 288,589
Cash flows used in investing activities	(787,464)	(1,534,122)
Cash flows provided by financing activities	457,203	1,244,796
Net decrease in cash	$ (4,145)	$ (737)

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Operating Activities. Net cash provided by operating activities for the six months ended June 30, 2009 and 2008 were $326.1 million and $288.6 million, respectively.

Net cash provided by operating activities increased in 2009 primarily due to the 65% increase in our average daily production volumes due to our recent drilling success in the Haynesville, Fayetteville and Eagle Ford Shales partially offset by a 62% decrease in our average realized natural gas equivalent price compared to the same period in the prior year. Production for the first six months of 2009 averaged 448 Mmcfe/d compared to 272 Mmcfe/d during the same period of 2008. Our natural gas equivalent price decreased $6.44 per thousand cubic feet of natural gas equivalent (Mcfe) to $4.01 per Mcfe from $10.45 per Mcfe in the prior year. As a result of our 2009 capital budget program, we expect to continue to increase our production volumes throughout 2009. However, we are unable to predict future production levels or future commodity prices, and, therefore, we cannot provide any assurance about future levels of net cash provided by operating activities.

Investing Activities. The primary driver of cash used in investing activities is capital spending, inclusive of acquisitions and net of dispositions. Cash used in investing activities was $787.5 million and $1.5 billion for the six months ended June 30, 2009 and 2008, respectively.

During the first six months of 2009, we spent $748.1 million on acquisitions of oil and gas properties and capital expenditures. To date in 2009, we participated in the drilling of 297 gross wells (75.2 net wells). We spent an additional $145.4 million on other operating property and equipment expenditures, primarily to fund the completion of gathering systems in the Fayetteville Shale in Arkansas and the development of our gathering systems in the Haynesville Shale in Louisiana and the Eagle Ford Shale in Texas.

During the first six months of 2009, we sold a net $106.0 million of marketable securities. These marketable securities have been classified and accounted for as trading securities and were used primarily to fund a portion of our 2009 capital program.

During the first six months of 2008, we spent $1.4 billion on capital expenditures, of which approximately $1.1 billion related to acquisitions. Our acquisitions were partially funded by the remaining restricted cash that we had deposited with a qualified intermediary following the sale of our Gulf Coast properties to facilitate like-kind exchange transactions. In addition, we participated in the drilling of 328 gross wells in 2008 (121.7 net wells), six of which were dry holes. We spent an additional $31.0 million on other operating property and equipment during the first six months of 2008 as well, primarily to fund the development of gathering systems in the Fayetteville Shale in Arkansas.

On November 30, 2007, we closed the sale of our Gulf Coast properties for $825 million, before customary closing adjustments, consisting of $700 million in cash and a $125 million note from the purchaser (the Note). The Note matured five years and ninety-one days from the closing date and bore interest at 12% per annum payable in kind at the purchaser s option. The economic effective date for the sale was July 1, 2007. Proceeds from the sale were recorded as a reduction to the carrying value of our full cost pool. In conjunction with the closing of this sale, we deposited $650 million with a qualified intermediary to facilitate potential like-kind exchange transactions. At December 31, 2007, we had $269.8 million remaining for use in future acquisitions, all of which was utilized for property acquisitions during the fourth quarter of 2007 and first quarter of 2008. On April 28, 2008, the purchaser redeemed the Note for $100 million.

During the first six months of 2008, we used excess funds from our debt and equity offerings discussed below to purchase a net $490 million of marketable securities. These marketable securities were classified and accounted for as trading securities and were used primarily to fund our leasing and acquisition activities in the Haynesville Shale.

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Financing Activities. Net cash flows provided by financing activities were $457.2 million and $1.2 billion for the six months ended June 30, 2009 and 2008, respectively. Cash flows provided by financing activities in the first half of 2009 were the result of the issuance of new senior notes and the sale of our common stock in an underwritten public offering.

On March 4, 2009, we sold an aggregate of 22.0 million shares of our common stock in an underwritten public offering. The net proceeds from this offering were approximately $376 million, after deducting underwriting discounts and commissions and estimated expenses.

On January 27, 2009, we completed a private placement offering to eligible purchasers of an aggregate principal amount of $600 million 10.5% senior notes due August 1, 2014. The net proceeds from the sale of the 2014 Notes were approximately $535.4 million, after deducting the initial purchasers discounts and estimated offering expenses and commissions.

On February 1, 2008, we sold an aggregate of 20.7 million shares of our common stock in an underwritten public offering. The net proceeds from the sale were approximately $297 million, after deducting underwriting discounts and commissions and estimated expenses.

On May 13, 2008, we sold an aggregate of 25.0 million shares of our common stock in an underwritten public offering. Pursuant to the underwriting agreement, we granted the underwriters a 30-day option to purchase up to an additional 3.75 million shares of common stock at the public offering price less underwriting discounts and commissions. The underwriters exercised in full their option to purchase additional shares of common stock which closed on May 23, 2008. The net proceeds from these sales were approximately $727 million, after deducting underwriting discounts and commissions and estimated expenses.

On May 13, 2008, we issued $500 million aggregate principal amount of the 2015 Notes in a private placement under the Securities Act of 1933, as amended. The net proceeds from the sale of the 2015 Notes were approximately $490 million, after deducting the initial purchasers discounts and estimated offering expenses, including commissions.

On June 19, 2008, we issued an additional $300 million aggregate principal amount of 2015 Notes in a private placement under the Securities Act of 1933, as amended. The net proceeds from the sale of the 2015 Notes were approximately $294 million, after deducting the initial purchaser s discount and estimated offering expenses.

Capital financing and excess cash flow are used to repay borrowings under our Senior Credit Agreement to the extent available. During the first six months of 2009, we had net borrowings of $92.5 million after the application of a portion of the net proceeds from our issuance of the 2014 Notes and the sale of our common stock as discussed above to repay amounts outstanding on the Senior Credit Agreement and cash requirements of our drilling and acquisition activities. As of June 30, 2009, the Senior Credit Agreement had a $950 million borrowing base and no outstanding borrowings. During the first six months of 2008, we had net borrowings of $228.6 million.

Contractual Obligations

We have no material changes in our long-term commitments associated with our capital expenditure plans or operating agreements other than those described below. Our level of capital expenditures will vary in future periods depending on the success we experience in our acquisition, development and exploration activities, oil and natural gas price conditions and other related economic factors. Currently no sources of liquidity or financing are provided by off-balance sheet arrangements or transactions with unconsolidated, limited-purpose entities.

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As of June 30, 2009, we have drilling rigs under contract with a total commitment of $355.1 million over four years. At December 31, 2008, we had drilling rigs under contract with a total commitment of $433.0 million over four years.

We have various other contractual commitments pertaining to exploration, development and production activities. We have work related commitments for, among other things, pipeline and well equipment, obtaining and processing seismic data and natural gas pipeline transportation. At June 30, 2009 and December 31, 2008, these work related commitments totaled $1.1 billion over 16 years and $507.8 million over 20 years, respectively.

Critical Accounting Policies and Estimates

Our discussion and analysis of our financial condition and results of operation are based upon the condensed consolidated financial statements, which have been prepared in accordance with accounting principles generally accepted in the United States. Preparation of these financial statements requires us to make estimates and judgments that affect the reported amounts of assets, liabilities, revenues and expenses. There have been no changes to our critical accounting policies from those described in our annual report on Form 10-K, as amended, for the year ended December 31, 2008.

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Results of Operations

Quarters ended June 30, 2009 and 2008

We reported a net loss of $22.0 million for the three months ended June 30, 2009 compared to a net loss of $92.8 million for the comparable period in 2008. The decrease in our net loss of $70.8 million from the three months ended June 30, 2009 was primarily driven by $16.0 million net gain on derivative contracts for the three months ended June 30, 2009 compared to the net loss of $277.6 million on derivative contracts in the prior year. In addition our production volumes increased 71% over prior year, offset by a 69% decrease in our average realized natural gas equivalent price.

	Three Months Ended June 30,		
In thousands (except per unit and per Mcfe amounts)	**2009**	**2008**	**Change**
Net loss available to common stockholders	$ (22,004)	$ (92,766)	$ 70,762
Operating revenues:			
Oil and natural gas	163,983	304,633	(140,650)
Marketing	63,317		63,317
Expenses:			
Marketing	60,292		60,292
Production:			
Lease operating	18,704	12,903	5,801
Workover and other	205	1,249	(1,044)
Taxes other than income	12,537	14,036	(1,499)
Gathering, transportation and other	22,633	10,944	11,689
General and administrative:			
General and administrative	20,185	14,133	6,052
Stock-based compensation	3,807	3,081	726
Depletion, depreciation and amortization:			
Depletion Full cost	80,656	85,597	(4,941)
Depreciation Other	3,424	786	2,638
Accretion expense	355	311	44
Net gain (loss) on derivative contracts	16,006	(277,605)	293,611
Interest expense and other	(55,880)	(35,154)	(20,726)
Income tax benefit	13,368	58,400	(45,032)
Production:			
Natural Gas Mmcf (1)	41,485	23,413	18,072
Crude Oil Mbbl	407	385	22
Natural Gas Equivalent Mmcfe	43,927	25,720	18,207
Average Daily Production Mmcfe	483	283	200
Average price per unit (2):			
Gas price per Mcf (1)	$ 3.28	$ 10.99	$ (7.71)
Oil price per Bbl	53.72	117.85	(64.13)
Equivalent per Mcfe	3.60	11.77	(8.17)
Average cost per Mcfe:			
Production:			
Lease operating	0.43	0.50	(0.07)
Workover and other		0.05	(0.05)
Taxes other than income	0.29	0.55	(0.26)
Gathering, transportation and other	0.52	0.43	0.09
General and administrative:			
General and administrative	0.46	0.55	(0.09)
Stock-based compensation	0.09	0.12	(0.03)
Depletion	1.84	3.33	(1.49)

(1) Approximately 1% and 3% of natural gas production represents natural gas liquids (calculated with a 6:1 equivalent ratio) with an average price of $27.25 per barrel (Bbl) and $65.71 per Bbl for the three months ended June 30, 2009 and 2008, respectively.

(2) Amounts exclude the impact of cash paid/received on settled contracts as we did not elect to apply hedge accounting.

For the three months ended June 30, 2009, oil and natural gas revenues decreased $140.7 million from the same period in 2008, to $164.0 million. The decrease was primarily due to the decrease of $8.17 per Mcfe in our realized average price to $3.60 per Mcfe from $11.77 per Mcfe in the prior year. This decrease per Mcfe led to a decrease in oil and natural gas revenues of $359 million. The effect of the decrease in price was partially offset by an increase in production of 18,207 Mmcfe, or 71% over the three months ended June 30, 2008, due to our recent drilling successes in resource-style plays in Louisiana, Arkansas and Texas. Increased production led to an approximate $218 million increase in revenues for the three months ended June 30, 2009.

We had marketing revenues of $63.3 million and marketing expenses of $60.3 million for the three months ended June 30, 2009, resulting in a net margin of $3 million. During the fourth quarter of 2008, we began purchasing and selling third party natural gas produced from wells we operate. We report the revenues and expenses related to these marketing activities on a gross basis as part of our operating revenues and operating expenses. Marketing revenues are recorded at the time natural gas is physically delivered to third parties at a fixed or index price. Marketing expenses attributable to gas purchases are recorded as we take physical title to the natural gas and transport the purchased volumes to the point of sale.

Lease operating expenses increased $5.8 million for the three months ended June 30, 2009. The increase was primarily due to the increase in production volumes as a result of our recent drilling successes in our resource-style plays in Louisiana, Arkansas and Texas. On a per unit basis, lease operating expenses decreased from $0.50 per Mcfe in 2008 to $0.43 per Mcfe in 2009. This decrease on a per unit basis is primarily due to the increase in production in our resource-style plays which have lower lease operating costs.

Taxes other than income decreased $1.5 million for the three months ended June 30, 2009 as compared to the same period in 2008. The largest components of taxes other than income are production and severance taxes which are generally assessed as either a fixed rate based on production or as a percentage of gross oil and natural gas sales. On a per unit basis, taxes other than income decreased $0.26 per Mcfe to $0.29 per Mcfe compared to $0.55 per Mcfe in 2008. This decrease on a per unit basis is primarily attributable to severance tax refunds received in the current year as well as the increase in production associated with our resource-style play locations in Louisiana, Arkansas and Texas and, to a lesser extent, the overall decreases in our realized natural gas prices.

Gathering, transportation and other expense increased $11.7 million, or $0.09 per Mcfe, for the three months ended June 30, 2009 as compared to the same period in 2008. This increase was primarily due to an increase in production in the Fayetteville Shale which has higher gathering, transportation and other costs as well as the increase of costs associated with the production growth in the Haynesville Shale play.

General and administrative expense for the three months ended June 30, 2009 increased $6.1 million as compared to the same period in 2008. This increase was primarily attributable to a $3.4 million increase in payroll and employee costs, including salary, medical and incentives associated with the building of our work force as a result of the continued growth in our Company. Professional fees increased approximately $2.5 million due to increased legal and tax services as compared to the same period in 2008. Although overall costs have increased, general and administrative expense has decreased on a per Mcfe basis from $0.55 per Mcfe in 2008 to $0.46 per Mcfe in 2009 as production increases have exceeded our administrative expense increases.

Depletion for oil and natural gas properties is calculated using the unit of production method, which essentially depletes the capitalized costs associated with the evaluated properties plus future development costs based on the ratio of production volume for the current period to total remaining reserve volume for the evaluated properties. Depletion expense decreased $4.9 million for the three months ended June 30, 2009 from the same period in 2008, to $80.7 million. On a per unit basis, depletion expense decreased $1.49 per Mcfe to $1.84 per Mcfe. This decrease on a per unit basis is primarily due to the ceiling test impairment write-down of $1.7 billion we recorded at March 31, 2009 and $1.0 billion that we recorded at December 31, 2008.

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Other depreciation expense increased $2.6 million to $3.4 million for the three months ended June 30, 2009 compared to $0.8 million in the prior year. This increase is primarily due to the construction of our gas gathering system in the Fayetteville Shale in Arkansas and the Haynesville Shale in North Louisiana.

We enter into derivative commodity instruments to economically hedge our exposure to price fluctuations on our anticipated oil and natural gas production. Consistent with the prior year, we have elected not to designate any positions as cash flow hedges for accounting purposes, and accordingly, we recorded the net change in the mark-to-market value of these derivative contracts in the condensed consolidated statement of operations. At June 30, 2009, we had a $289.1 million derivative asset, $239.6 million of which was classified as current, and a $3.1 million derivative liability, $0.4 million of which was classified as current. The Company recorded a net derivative gain of $16.0 million ($82.4 million net unrealized loss and $98.4 million net gain for cash received on settled contracts) for the three months ended June 30, 2009 compared to a net derivative loss of $277.6 million ($229.1 million unrealized loss and a $48.5 million loss for cash paid on settled contracts) in the same period in 2008. This increase in our net derivative income is primarily attributable to the receipt of $98.4 million for settled contracts during the second quarter of 2009 as a result of the continued decline in natural gas prices in the current year.

Interest expense and other increased $20.7 million for the three months ended June 30, 2009 compared to the same period in 2008. Interest expense increased $25.8 million due to the issuance of new long-term debt ($10.0 million for the $800 million 7.875% senior notes due 2015 (the 2015 Notes) and $15.8 million for the $600 million 10.5% senior notes due August 1, 2014 (the 2014 Notes)). This was partially offset by a $3.0 million reduction in interest expense associated with the decrease in our outstanding balance on our Senior Credit Agreement compared to the prior year. Our interest expenses for the second quarter of 2009 included a $2.5 million credit for the capitalization of interest associated with the ongoing construction of our gas gathering systems. We made the decision in the second quarter of 2008 to withdraw our proposed Master Limited Partnership public offering which resulted in a charge of $3.4 million. The amortization of the discount recorded in conjunction with the issuance of the 2014 Notes increased interest expense approximately $1.7 million during the three months ended June 30, 2009 as compared to the prior year. Also contributing to the increase from prior year is the $2.1 million decrease in interest income for the three months ended June 30, 2009 compared to the same period in 2008.

Income tax benefit for the three months ended June 30, 2009 decreased $45.0 million from the same period in 2008. The decrease in income tax benefit from prior year was primarily due to our pre-tax loss of $35.4 million for the three months ended June 30, 2009 compared to our pre-tax loss of $151.2 million in 2008. The effective tax rates for the three months ended June 30, 2009 and 2008 were 37.8% and 38.6%, respectively. The decrease in our effective rate is primarily due to a reduced state rate tax resulting from the implementation of various tax planning strategies.

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Six Months ended June 30, 2009 and 2008

We reported a net loss of $1.0 billion for the six months ended June 30, 2009 compared to a net loss of $148.4 million for the comparable period in 2008. The increase in our net loss of $873.4 million from the six months ended June 30, 2009 was primarily driven by our full cost ceiling impairment of $1.7 billion before taxes, partially offset by our net gain on derivative contracts of $197.9 million compared to a net loss on derivative contracts of $420.3 million in the prior year.

In thousands (except per unit and per Mcfe amounts)	Six Months Ended June 30, 2009	2008	Change
Net loss available to common stockholders	$ (1,021,757)	$ (148,378)	$ (873,379)
Operating revenues:			
Oil and natural gas	337,745	519,571	(181,826)
Marketing	153,010		153,010
Expenses:			
Marketing	145,136		145,136
Production:			
Lease operating	35,115	25,297	9,818
Workover and other	928	1,786	(858)
Taxes other than income	24,717	25,000	(283)
Gathering, transportation and other	43,127	20,467	22,660
General and administrative:			
General and administrative	37,014	27,689	9,325
Stock-based compensation	6,617	5,679	938
Depletion, depreciation and amortization:			
Depletion Full cost	191,748	167,670	24,078
Depreciation Other	6,243	1,558	4,685
Accretion expense	700	593	107
Full cost ceiling impairment	1,732,486		1,732,486
Net gain (loss) on derivative contracts	197,928	(420,346)	618,274
Interest expense and other	(111,948)	(62,691)	(49,257)
Income tax benefit	625,339	90,827	534,512
Production:			
Natural gas Mmcf (1)	76,076	44,936	31,140
Crude oil MBbl	821	750	71
Natural gas equivalent Mmcfe	81,002	49,433	31,569
Daily production Mmcfe	448	272	176
Average price per unit (2):			
Natural gas price Mcf (1)	$ 3.77	$ 9.72	$ (5.95)
Crude oil price Bbl	45.85	106.66	(60.81)
Equivalent Mcfe	4.01	10.45	(6.44)
Average cost per Mcfe:			
Production:			
Lease operating	0.43	0.51	(0.08)
Workover and other	0.01	0.04	(0.03)
Taxes other than income	0.31	0.51	(0.20)
Gathering, transportation and other	0.53	0.41	0.12
General and administrative:			
General and administrative	0.46	0.56	(0.10)
Stock-based compensation	0.08	0.11	(0.03)
Depletion	2.37	3.39	(1.02)

(1) Approximately 1% and 3% of natural gas production represents natural gas liquids (calculated with a 6:1 equivalent ratio) with an average price of $25.32 per Bbl and $63.78 per Bbl for the six months ended June 30, 2009 and 2008, respectively.

(2) Amounts exclude the impact of cash paid/received on settled contracts as we did not elect to apply hedge accounting.

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For the six months ended June 30, 2009, oil and natural gas revenues decreased $181.8 million from the same period in 2008, to $337.7 million. The decrease was primarily due to the decrease of $6.44 per Mcfe in our realized average price to $4.01 per Mcfe from $10.45 per Mcfe in the prior year. This decrease per Mcfe led to a decrease in oil and natural gas revenues of $522 million. The effect of the decrease in price was partially offset by an increase in production of 31,569 Mmcfe or 64% over the six months ended June 30, 2008 due to our recent drilling successes in resource-style plays in Louisiana, Arkansas and Texas. Increased production led to an approximate $340 million increase in revenues for the six months ended June 30, 2009.

We had marketing revenues of $153.0 million and marketing expenses of $145.1 million for the six months ended June 30, 2009, resulting in a net margin of $7.9 million. During the fourth quarter of 2008, we began purchasing and selling third party natural gas produced from wells we operate. We report the revenues and expenses related to these marketing activities on a gross basis as part of our operating revenues and operating expenses. Marketing revenues are recorded at the time natural gas is physically delivered to third parties at a fixed or index price. Marketing expenses attributable to gas purchases are recorded as we take physical title to the natural gas and transport the purchased volumes to the point of sale.

Lease operating expenses increased $9.8 million for the six months ended June 30, 2009. The increase was primarily due to the increase in production volumes as a result of our recent drilling successes in our resource-style plays in Louisiana, Arkansas and Texas. On a per unit basis, lease operating expenses decreased from $0.51 per Mcfe in 2008 to $0.43 per Mcfe in 2009. This decrease on a per unit basis is primarily due to the increase in production in our resource-style plays which have lower lease operating costs.

Taxes other than income decreased $0.3 million for the six months ended June 30, 2009 as compared to the same period in 2008. The largest components of taxes other than income are production and severance taxes which are generally assessed as either a fixed rate based on production or as a percentage of gross oil and natural gas sales. On a per unit basis, taxes other than income decreased $0.20 per Mcfe to $0.31 per Mcfe compared to $0.51 per Mcfe in 2008. This decrease on a per unit basis is primarily attributable to severance tax refunds received in the current year as well as the increase in production associated with our resource-style play locations in Louisiana and Arkansas and, to a lesser extent, the overall decreases in our realized natural gas prices.

Gathering, transportation and other expense increased $22.7 million, or $0.12 per Mcfe, for the six months ended June 30, 2009 as compared to the same period in 2008. This increase was primarily due to an increase in production in the Fayetteville Shale which has higher gathering, transportation and other costs as well as the increase of costs associated with the production growth in the Haynesville Shale play.

General and administrative expense for the six months ended June 30, 2009 increased $9.3 million as compared to the same period in 2008. This increase was primarily attributable to a $6.7 million increase in employee expense, including salary, medical and incentives, associated with the continued building of our work force associated with the recent growth in our Company. Professional fees increased $2.6 million due to increased legal and tax services as compared to the same period in 2008. Although overall costs have increased, general and administrative expense has decreased on a per Mcfe basis from $0.56 per Mcfe in 2008 to $0.46 per Mcfe in 2009 as production increases have exceeded our administrative expense increases.

Depletion for oil and natural gas properties is calculated using the unit of production method, which essentially depletes the capitalized costs associated with the evaluated properties plus future development costs based on the ratio of production volume for the current period to total remaining reserve volume for the evaluated properties. Depletion expense increased $24.1 million for the six months ended June 30, 2009 from the same period in 2008, to $191.7 million. This increase was primarily attributable to the 31,569 Mcfe increase in production. On a per unit basis, depletion expense decreased $1.02 per Mcfe to $2.37 per Mcfe. This decrease on a per unit basis is primarily due to the ceiling test impairment write-down of $1.7 billion we recorded at March 31, 2009 and $1.0 billion that we recorded at December 31, 2008.

Other depreciation expense increased $4.7 million to $6.2 million for the six months ended June 30, 2009. This increase is primarily due to the construction of our gas gathering system in the Fayetteville Shale in Arkansas and the Haynesville Shale in North Louisiana.

We recorded a full cost ceiling impairment of approximately $1.7 billion for the six months ended June 30, 2009. A variety of economic and other factors have recently caused significant declines in oil and natural gas prices. We utilize the full cost method of accounting to account for our oil and natural gas exploration and development activities. Under this method of accounting, we are required on a quarterly basis to determine whether the book value of our oil and natural gas properties (excluding unevaluated properties) is less than or equal to the ceiling , based upon the expected after tax present value (discounted at 10%) of the future net cash flows from our proved reserves, calculated using prevailing oil and natural gas prices on the last day of the period, or a subsequent higher price under certain circumstances. Any excess of the net book value of our oil and natural gas properties over the ceiling must be recognized as a non-cash impairment expense. At March 31, 2009, our ceiling was calculated using prices of $49.66 per barrel of oil and $3.63 per Mmbtu. Accordingly, at March 31, 2009, our costs exceeded our ceiling limitation by approximately $1.7 billion, resulting in an approximate $1.7 billion write-down of our oil and natural gas properties. At June 30, 2009, our book value of our oil and natural gas properties did not exceed our ceiling limitation as natural gas prices increased to $3.89 per Mmbtu.

We enter into derivative commodity instruments to economically hedge our exposure to price fluctuations on our anticipated oil and natural gas production. Consistent with the prior year, we have elected not to designate any positions as cash flow hedges for accounting purposes, and accordingly, we recorded the net change in the mark-to-market value of these derivative contracts in the condensed consolidated statement of operations. At June 30, 2009, we had a $289.1 million derivative asset, $239.6 million of which was classified as current, and a $3.1 million derivative liability, $0.4 million of which was classified as current. The Company recorded a net derivative gain of $197.9 million ($18.4 million net unrealized gain and $179.5 million gain for cash received on settled contracts) for the six months ended June 30, 2009 compared to a net derivative loss of $420.3 million ($366.6 million unrealized loss and a $53.7 million loss for cash paid on settled contracts) in the same period in 2008. This increase in our net derivative income is primarily attributable to the continued decline in natural gas prices in the current year compared to the prior year.

Interest expense and other increased $49.3 million for the six months ended June 30, 2009 compared to the same period in 2008. There were several factors creating the increase including issuance of the new senior debt, an increase in debt issue costs, a decrease in our Senior Credit Agreement interest expense, and an increase in discount amortization of the new senior debt. Interest expense increased $52.9 million due to the issuance of new long-term debt ($25.8 million for the $800 million 7.875% senior notes due 2015 (the 2015 Notes) and $27.1 million for the $600 million 10.5% senior notes due August 1, 2014 (the 2014 Notes)). This was partially offset by a $9.3 million reduction in interest expense associated with the decrease in our outstanding balance on our Senior Credit Agreement compared to the prior year. In the second quarter of 2009, interest expense included a $2.5 million credit for the capitalization of interest associated with the ongoing construction of our gas gathering systems. Amortization of debt issue costs for two new instruments accounted for $2.4 million of the interest expense; the 2015 Notes were issued in the second quarter of 2008 and the 2014 Notes were issued in the first quarter of 2009. The amortization of the discount recorded in conjunction with the issuance of the 2014 Notes increased interest expense approximately $2.9 million in the six months ended June 30, 2009 compared to the same period in 2008. In the second quarter of 2008, interest expense included a $3.4 million write-off for costs associated with the Master Limited Partnership. Interest income decreased approximately $5.6 million in the current period compared to the prior year.

Income tax benefit for the six months ended June 30, 2009 increased $534.5 million from the same period in 2008. The increase in income tax benefit from prior year was primarily due to our pre-tax loss of $1,647.1 million for the six months ended June 30, 2009 compared to our pre-tax loss of $239.2 million in 2008. The effective tax rates for the six months ended June 30, 2009 and 2008 were 38.0%.

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Recently Issued Accounting Pronouncements

We discuss recently adopted and issued accounting standards in Item 1. *Condensed Consolidated Financial Statements* Note 1, *Financial Statement Presentation*.

Item 3. Quantitative and Qualitative Disclosures about Market Risk
Derivative Instruments and Hedging Activity

We are exposed to various risks including energy commodity price risk. When oil and natural gas prices decline significantly our ability to finance our capital budget and operations could be adversely impacted. We expect energy prices to remain volatile and unpredictable, therefore we have designed a risk management policy which provides for the use of derivative instruments to provide partial protection against declines in oil and natural gas prices by reducing the risk of price volatility and the affect it could have on our operations. The types of derivative instruments that we typically utilize include collars, swaps, basis swaps and puts. The total volumes which we hedge through the use of our derivative instruments varies from period to period, however, generally our objective is to hedge approximately 65% to 70% of our current and anticipated production. Our hedge policies and objectives may change significantly as commodities prices or price futures change.

We are exposed to market risk on our open hedged positions, to the extent our counterparties have liquidity issues and are unable to settle their obligations with us. The current economic crisis may have a negative impact on the liquidity of the counterparties to our hedging agreements, which increases the risk of those counterparties failing to perform under those agreements. If those parties default, we could be exposed to the price risks we had sought to mitigate and our financial condition and results of operations may be materially and adversely affected. Please refer to Item 1. *Condensed Consolidated Financial Statements* Note 8, *Derivatives* for additional information.

We have also been exposed to interest rate risk on our variable interest rate debt. If interest rates increase, our interest expense would increase and our available cash flow would decrease. Periodically, we may look to utilize interest rate swaps to reduce the exposure to market rate fluctuations by converting variable interest rates to fixed interest rates. At June 30, 2009, we did not have any open positions that converted our variable interest rate debt to fixed interest rates. We continue to monitor our risk exposure as we incur future indebtedness at variable interest rates and will look to continue our risk management policy as situations present themselves.

During the second quarter of 2009, we entered into interest rate swaps to convert a portion of our long-term debt from a fixed interest rate to a variable interest rate. At June 30, 2009 we had five open interest rate swap positions that converted our $600 million senior notes with a 10.5% fixed interest rate to a variable interest rate with a fixed spread ranging from 1.50% to 1.55% against LIBOR for the next two years.

The Company accounts for its derivative activities under the provisions of SFAS 133, *Accounting for Derivative Instruments and Hedging Activities*, as amended. This statement, as amended, establishes accounting and reporting that every derivative instrument be recorded on the balance sheet as either an asset or liability measured at fair value. See Item 1. *Condensed Consolidated Financial Statements* Note 8, *Derivatives* for more details.

Interest Sensitivity

Historically, we have been exposed to interest rate risk exposure primarily from fluctuations in short-term rates, which are LIBOR and ABR based. These fluctuations can cause reductions of earnings or cash flows due to increases in the interest rates that we have historically paid on these obligations. At June 30, 2009, total debt excluding related discounts and premiums was $2.4 billion which bears interest at a weighted average fixed interest rate of 8.8% per year. At June 30, 2009, we did not have any amounts drawn under our senior revolving credit facility.

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Item 4. Controls and Procedures

In accordance with Exchange Act Rule 13a-15 and 15d-15, we carried out an evaluation, under the supervision and with the participation of management, including our Chief Executive Officer and our Chief Financial Officer, of the effectiveness of our disclosure controls and procedures as of the end of the period covered by this report. Based on that evaluation, our Chief Executive Officer and Chief Financial Officer concluded that our disclosure controls and procedures were effective as of June 30, 2009 to provide reasonable assurance that information required to be disclosed in our reports filed or submitted under the Exchange Act is recorded, processed, summarized and reported within the time periods specified in the Securities and Exchange Commission s rules and forms. Our disclosure controls and procedures include controls and procedures designed to ensure that information required to be disclosed in reports filed or submitted under the Exchange Act is accumulated and communicated to our management, including our Chief Executive Officer and Chief Financial Officer, as appropriate, to allow timely decisions regarding required disclosure.

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

PART II. OTHER INFORMATION

Item 1. Legal Proceedings

From time to time, we may be a plaintiff or defendant in a pending or threatened legal proceeding arising in the normal course of our business. While the outcome and impact of currently pending legal proceedings cannot be predicted with certainty, our management and legal counsel believe that the resolution of these proceedings through settlement or adverse judgment will not have a material adverse effect on our condensed consolidated operating results, financial position or cash flows.

Under rules promulgated by the SEC, administrative or judicial proceedings arising under any Federal, State or local provisions that have been enacted or adopted regulating the discharge of materials into the environment or primary for the purpose of protecting the environment are disclosed if the governmental authority is a party to such proceeding and the proceeding involves potential monetary sanctions of $100,000 or more. We are not party to any such proceedings, except as described below.

We are involved in natural gas exploration in the Fayetteville Shale Play in North Central Arkansas. Our subsidiary, Hawk Field Services, LLC, has been constructing a pipeline to transport natural gas from wellheads. Hawk Field Services activities are being performed pursuant to required environmental permits issued by the Arkansas Department of Environmental Quality (ADEQ) and the United States Army Corps of Engineers (Corps). The terrain in and around the Fayetteville Shale Play is very hilly and requires that the pipeline cross numerous small creeks and streams. Some of these streams ultimately drain into larger waters that are home to an endangered freshwater mussel known as the Speckled Pocketbook (*Lampsilis streckeri*).

In 2008, the United States Fish and Wildlife Service (USFWS) opened an investigation into the activities of Hawk Field Services and the Company in the Fayetteville Shale Play. The investigation focused on the pipeline stream crossings and potential impacts on the Speckled Pocketbook. On April 22, 2009, we received a letter from the United States Attorney s Office for the Eastern District of Arkansas and the Environmental Crimes Section of the United States Department of Justice notifying us that we are under criminal investigation for alleged violations of the Federal Clean Water Act and the Federal Endangered Species Act with respect to the endangered Speckled Pocketbook. The full details of the investigation are not yet known. In addition, the ADEQ has issued notices of violations to us for failure to properly install or maintain sediment control structures in connection with construction of the pipeline. At this time, we are not able to estimate our potential exposure related to these matters. We potentially could, however, be indicted for felony violations of the Endangered Species Act and Clean Water Act, plead guilty to the violations, or enter into an alternative agreement to resolve the allegations. We could be subject to criminal and/or civil sanctions, including requirements to pay a monetary penalty and undertake certain injunctive measures, such as implementing additional construction management practices to control the discharge of sediment from our construction activities or other restrictions on our operations. The implementation of these management practices or other injunctive measures could delay or increase the cost of construction.

On July 27, 2009, we received a Cease and Desist Order from the Corps alleging violations of the Federal Clean Water Act for unauthorized land clearing and discharges of dredged or fill material into wetlands associated with the development of three gas wells in Bossier, Caddo, Red River Parishes in Louisiana. We are investigating these allegations and are unable at this time to estimate our potential exposure related to this matter. We could be required to pay a monetary penalty, undertake certain restoration or mitigation activities, and cease development of the subject wells until the matter is resolved. If we are required to cease development of these wells, it would delay and impact our ability to produce and sell gas from these wells.

Item 1A. Risk Factors

There have been no changes to the risk factors described in the Company s annual report on Form 10-K, as amended, for the year ended December 31, 2008, other than those described below.

Estimates of proved oil and natural gas reserves are imprecise and any material inaccuracies in these reserve estimates will materially affect the quantities and the value of our reserves.

Our report on Form 10-K for the year ended December 31, 2008, as amended, contains estimates of our proved oil and natural gas reserves. These estimates are based upon various assumptions, including assumptions required by the SEC relating to oil and natural gas prices, drilling and operating expenses, capital expenditures, taxes and availability of funds. The process of estimating oil and natural gas reserves is complex. This process requires significant decisions and assumptions in the evaluation of available geological, geophysical, engineering and economic data for each reservoir. Therefore, these estimates are inherently imprecise.

Actual future production, oil and natural gas prices, revenues, taxes, development expenditures, operating expenses and quantities of recoverable oil and natural gas reserves will vary from those estimated. Any significant variance could materially affect the estimated quantities and the value of our reserves. Our properties may also be susceptible to hydrocarbon drainage from production by other operators on adjacent properties. In addition, we may adjust estimates of proved reserves to reflect production history, results of exploration and development, prevailing oil and natural gas prices and other factors, many of which are beyond our control.

At December 31, 2008, approximately 44% of our estimated reserves were classified as proved undeveloped. Recovery of proved undeveloped reserves requires significant capital expenditures and successful drilling operations. The reserve data assumes that we will make significant capital expenditures to develop our reserves. Although we have prepared estimates of these oil and natural gas reserves and the costs associated with development of these reserves in accordance with SEC regulations, actual capital expenditures will likely vary from estimated capital expenditures, development may not occur as scheduled and actual results may not be as estimated.

We may incur substantial costs to comply with, and demand for our products may be reduced by, climate change legislation and regulatory initiatives.

Recent studies have indicated that emissions of certain gases may be contributing to warming of the Earth s atmosphere. In response to these studies, many nations have agreed to limit emissions of greenhouse gases pursuant to the United Nations Framework Convention on Climate Change, also known as the Kyoto Protocol. Methane, a primary component of natural gas, and carbon dioxide, a byproduct of the burning of oil and natural gas, and refined petroleum products, are greenhouse gases regulated by the Kyoto Protocol. Although the United States is not participating in the Kyoto Protocol, several states have adopted legislation and regulations to reduce emissions of greenhouse gases. Restrictions on emissions of methane or carbon dioxide that may be imposed in various states could adversely affect our operations and demand for our products. Additionally, the United States Supreme Court has ruled, in Massachusetts, et al. v. EPA, that the United States Environmental

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Protection Agency (EPA) abused its discretion under the Clean Air Act by refusing to regulate carbon dioxide emissions from mobile sources. As a result of the Supreme Court decision and the change in presidential administrations, the EPA recently issued a proposed finding that may lead to the agency promulgating federal greenhouse gas regulations and emissions limits under the Clean Air Act, even without Congressional action. The EPA s proposed finding could result in federal regulation of carbon dioxide emissions and other greenhouse gases, and may affect the outcome of other climate change lawsuits pending in United States federal courts in a manner unfavorable to our industry. Currently, our operations are not adversely impacted by existing state and local climate change initiatives and, at this time, it is not possible to accurately estimate how potential future laws or regulations addressing greenhouse gas emissions would impact our business. Depending on the nature of potential regulations and legislation, such future laws and regulations could result in increased compliance costs or additional operating restrictions, and could have a material adverse effect on our business or demand for the oil and natural gas we produce.

Certain U.S. federal income tax deductions currently available with respect to oil and gas exploration and development may be eliminated as a result of future legislation.

President Obama s Proposed Fiscal Year 2010 Budget includes proposed legislation that would, if enacted into law, make significant changes to United States tax laws, including the elimination of certain key United States federal income tax incentives currently available to oil and natural gas exploration and production companies. These changes include, but are not limited to, (i) the repeal of the percentage depletion allowance for oil and natural gas properties, (ii) the elimination of current deductions for intangible drilling and development costs, (iii) the elimination of the deduction for certain domestic production activities, and (iv) an extension of the amortization period for certain geological and geophysical expenditures. It is unclear whether any such changes will be enacted or how soon any such changes could become effective. The passage of any legislation as a result of these proposals or any other similar changes in United States federal income tax laws could negatively affect our financial condition and results of operations.

The adoption of climate change legislation by Congress could result in increased operating costs and reduced demand for the oil and natural gas we produce.

On June 26, 2009, the United States House of Representatives approved adoption of the American Clean Energy and Security Act of 2009, also known as the Waxman-Markey cap-and-trade legislation or ACESA. One of the purpose of ACESA is to control and reduce emissions of greenhouse gases, or GHGs, in the United States. GHGs are certain gases, including carbon dioxide and methane, that may be contributing to warming of the Earth s atmosphere and other climatic changes. ACESA would establish an economy-wide cap on emissions of GHGs in the United States and would require an overall reduction in GHG emissions of 17% (from 2005 levels) by 2020, and by over 80% by 2050. Under ACESA, most sources of GHG emissions would be required to obtain GHG emission allowances corresponding to their annual emissions of GHGs. The number of emission allowances issued each year would decline as necessary to meet ACESA s overall emission reduction goals. As the number of GHG emission allowances declines each year, the cost or value of allowances is expected to escalate significantly. The net effect of ACESA will be to impose increasing costs on the combustion of carbon-based fuels such as oil, refined petroleum products, and natural gas.

The United States Senate has begun work on its own legislation for controlling and reducing emissions of GHGs in the United States. If the Senate adopts GHG legislation that is different from ACESA, the Senate legislation would need to be reconciled with ACESA and both chambers would be required to approve identical legislation before it could become law. President Obama has indicated that he is in support of the adoption of legislation to control and reduce emissions of GHGs through an emission allowance permitting system that results in fewer allowances being issued each year but that allows parties to buy, sell and trade allowances as needed to fulfill their GHG emission obligations. Although it is not possible at this time to predict whether or when the Senate may act on climate change legislation or how any bill approved by the Senate would be reconciled with ACESA, any laws or regulations that may be adopted to restrict or reduce emissions of GHGs could require us to incur increased operating costs, and could have an adverse effect on demand for the oil and natural gas we produce, depending on the applicability to company operations and the refining, processing, and use of oil and natural gas.

The adoption of derivatives legislation by Congress could have an adverse impact on our ability to hedge risks associated with our business.

Congress is currently considering legislation to impose restrictions on certain transactions involving derivatives, which could affect the use of derivatives in hedging transactions. ACESA contains provisions that would prohibit private energy commodity derivative and hedging transactions. ACESA would expand the power of the Commodity Futures Trading Commission, or CFTC, to regulate derivative transactions related to energy commodities, including oil and natural gas, and to mandate clearance of such derivative contracts through registered derivative clearing organizations. Under ACESA, the CFTC s expanded authority over energy derivatives would terminate upon the adoption of general legislation covering derivative regulatory reform. The Chairman of the CFTC has announced that the CFTC intends to conduct hearings to determine whether to set limits on trading and positions in commodities with finite supply, particularly energy commodities, such as crude oil, natural gas and other energy products. The CFTC also is evaluating whether position limits should be applied consistently across all markets and participants. In addition, the Treasury Department recently has indicated that it intends to propose legislation to subject all OTC derivative dealers and all other major OTC derivative market participants to substantial supervision and regulation, including by imposing conservative capital and margin requirements and strong business conduct standards. Derivative contracts that are not cleared through central clearinghouses and exchanges may be subject to substantially higher capital and margin requirements. Although it is not possible at this time to predict whether or when Congress may act on derivatives legislation or how any climate change bill approved by the Senate would be reconciled with ACESA, any laws or regulations that may be adopted that subject us to additional capital or margin requirements relating to, or to additional restrictions on, our trading and commodity positions could have an adverse effect on our ability to hedge risks associated with our business or on the cost of our hedging activity.

Federal and state legislation and regulatory initiatives relating to hydraulic fracturing could result in increased costs and additional operating restrictions or delays.

Congress is currently considering legislation to amend the federal Safe Drinking Water Act to require the disclosure of chemicals used by the oil and natural gas industry in the hydraulic fracturing process. Hydraulic fracturing involves the injection of water, sand and chemicals under pressure into rock formations to stimulate natural gas production. Sponsors of bills currently pending before the Senate and House of Representatives have asserted that chemicals used in the fracturing process could adversely affect drinking water supplies. The proposed legislation would require the reporting and public disclosure of chemicals used in the fracturing process, which could make it easier for third parties opposing the hydraulic fracturing process to initiate legal proceedings based on allegations that specific chemicals used in the fracturing process could adversely affect groundwater. In addition, these bills, if adopted, could establish an additional level of regulation at the federal level that could lead to operational delays or increased operating costs and could result in additional regulatory burdens that could make it more difficult to perform hydraulic fracturing and increase our costs of compliance and doing business.

Delay or increased difficulties in the construction of gathering lines and well sites in our areas of operations or in the receipt of environmental regulatory approvals could adversely affect our business.

Natural gas exploration and production and related construction activities in some of the areas in which we operate, including construction of well sites, access roads, and gathering lines, have come under increased environmental regulatory scrutiny. Obtaining regulatory approvals or complying with conditions of approvals, such as construction best management practices, could become more difficult and costly. Delays or difficulties in obtaining regulatory approvals or complying with conditions of approvals could delay or otherwise affect our ability to produce gas from these areas.

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

The following table sets forth certain information with respect to the surrender of our common stock by employees in exchange for the payment of certain tax obligations during the three months ended June 30, 2009.

	Total Number of Shares Purchased[1]	Average Price Paid Per Share	Total Number of Shares Purchased as Part of Publicly Announced Plans or Programs	Maximum Number (or Approximate Dollar Value) of Shares that May Yet Be Purchased Under the Plans or Programs
April 2009	2,523	$ 20.43		
May 2009	978	$ 23.44		
June 2009	662	$ 24.53		

(1) All of the shares were surrendered by employees in exchange for the payment of tax withholding upon the vesting of restricted stock awards. The acquisition of the surrendered shares was not part of a publicly announced program to repurchase shares of our common stock, nor were they considered as or accounted for as Treasury shares.

Item 3. Defaults Upon Senior Securities

None.

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

Our annual meeting of stockholders was held on June 18, 2009 in Houston, Texas for the purpose of voting on six proposals.

1. The first of those proposals related to the election of individuals to serve as Class II directors of Petrohawk for three year terms expiring in 2012. The three directors elected and the tabulation of votes (both in person and by proxy) was as follows:

Nominees for Directors	Votes For	Witheld
James W. Christmas	229,529,550	21,374,537
James L. Irish III	211,405,831	39,498,256
Robert C. Stone, Jr.	228,075,166	22,828,921

Our continuing directors after the annual meeting include Floyd C. Wilson, Tucker S. Bridwell, Thomas R. Fuller, Gary A. Merriman, Robert G. Raynolds and Christopher A. Viggiano.

The second through sixth proposals, as well as the results, were as follows.

2. To ratify and approve an amendment to our Certificate of Incorporation to increase the number of shares of our common stock available for issuance from 300 million shares to 500 million shares, which was ratified and approved:

For	Against	Abstain	Broker Non-Votes
216,984,063	33,330,320	586,698	

3. To ratify and approve an amendment to our 2004 Employee Incentive Plan to increase the number of shares of our common stock that may be issued under the plan by 5.3 million shares, which was ratified and approved:

For	Against	Abstain	Broker Non-Votes
209,559,523	13,535,625	487,011	27,321,930

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4. To ratify and approve an amendment to our 2004 Non-Employee Director Incentive Plan to increase the number of shares of our common stock that may be issued under the plan by 0.5 million shares, which was ratified and approved:

For	Against	Abstain	Broker Non-Votes
171,783,002	51,287,101	512,056	27,321,930

5. To ratify and approve an amendment to our Certificate of Incorporation to allow our board of directors to amend our bylaws, which was not ratified and approved; and

For	Against	Abstain	Broker Non-Votes
71,605,405	178,932,365	366,312	

6. To ratify the appointment of Deloitte & Touche LLP, an independent registered public accounting firm, as our independent registered public accountants for the fiscal year ending December 31, 2009, which was ratified and approved:

For	Against	Abstain	Broker Non-Votes
249,683,016	999,360	221,708	

Item 5. Other Information

None.

Item 6. Exhibits

The following documents are included as exhibits to this Form 10-Q. Those exhibits incorporated by reference are so indicated by the information supplied with respect thereto. Those exhibits which are not incorporated by reference are attached hereto.

Exhibit No	Description
3.1	Certificate of Incorporation for Petrohawk Energy Corporation (Incorporated by reference to Exhibit 3.1 to our Form S-8 (File No. 333-117733) filed on July 29, 2004).
3.2	Certificate of Amendment to Certificate of Incorporation for Petrohawk Energy Corporation (Incorporated by reference to Exhibit 3.1 of our Current Report on Form 8-K filed on November 24, 2004).
3.3	Certificate of Amendment of Certificate of Incorporation of Petrohawk Energy Corporation (Incorporated by reference to Exhibit 3.1 of our Current Report on Form 8-K filed on August 3, 2005).
3.4	Amended and Restated Bylaws of Petrohawk Energy Corporation effective as of July 12, 2006 (Incorporated by reference to Exhibit 3.2 of our Current Report on Form 8-K filed on July 17, 2006).
3.5	Certificate of Amendment to Certificate of Incorporation of Petrohawk Energy Corporation (Incorporated by reference to Exhibit 3.1 of our Current Report on Form 8-K filed on July 17, 2006).
3.6	Certificate of Designations of Series A Junior Preferred Stock of Petrohawk Energy Corporation effective as of October 15, 2008 (Incorporated by reference to Exhibit 3.1 of our Current Report on Form 8-K filed on October 16, 2008).

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Exhibit No	Description
3.7	Certificate of Amendment to Certificate of Incorporation of Petrohawk Energy Corporation (Incorporated by reference to Exhibit 3.1 of our Current Report on Form 8-K filed on June 23, 2009).
4.1	Indenture dated as of April 8, 2004, among Mission Resources Corporation, the Guarantors named therein and The Bank of New York, as Trustee, relating to Petrohawk Energy Corporation s 9 7/8% Senior Notes due 2011 (Incorporated by reference to Exhibit 4.1 to Mission Resources Corporation s Current Report on Form 8-K/A filed on April 15, 2004).
4.2	First Supplemental Indenture dated as of July 28, 2005, among Petrohawk Energy Corporation, the successor by way of merger to Mission Resources Corporation, the parties named therein as Existing Subsidiary Guarantors, the parties named therein as Additional Subsidiary Guarantors, and The Bank of New York Trust Company, N.A., as successor trustee to The Bank of New York (Incorporated by reference to Exhibit 4.2 to our Current Report on Form 8-K filed on August 3, 2005).
4.3	Second Supplemental Indenture dated as of July 12, 2006, among Petrohawk Energy Corporation, as successor by merger to Mission Resources Corporation, the parties named therein as subsidiary guarantors, and The Bank of New York Trust Company, N.A., as trustee (Incorporated by reference to Exhibit 4.2 of our Current Report on Form 8-K filed on July 17, 2006).
4.4	Indenture dated April 1, 2004 among KCS Energy, Inc., U.S. Bank National Association, as trustee, and the subsidiary guarantors named therein, relating to KCS Energy, Inc. s 7 1/8% senior notes due 2012 (Incorporated by reference to Exhibit 4.1 to KCS Energy, Inc. s Quarterly Report on Form 10-Q filed on May 10, 2004).
4.5	First Supplemental Indenture, dated as of April 8, 2005, to Indenture dated as of April 1, 2004, among KCS Energy, Inc., certain of its subsidiaries and U.S. Bank National Association (Incorporated by reference to Exhibit 4.1 of KCS Energy, Inc. s Form 8-K filed on April 11, 2005).
4.6	Second Supplemental Indenture dated July 12, 2006 among Petrohawk Energy Corporation, the successor by way of merger to KCS Energy, Inc., the parties named therein as guarantors, and U.S. Bank National Association, as trustee (Incorporated by reference to Exhibit 4.4 to our Current Report on Form 8-K filed on July 17, 2006).
4.7	Third Supplemental Indenture dated as of July 12, 2006 among Petrohawk Energy Corporation, the successor by way of merger to KCS Energy, Inc., the parties named therein as existing guarantors, the parties named therein as new guarantors, and U.S. Bank National Association, as trustee (Incorporated by reference to Exhibit 4.5 to our Current Report on Form 8-K filed on July 17, 2006).
4.8	Fourth Supplemental Indenture dated as of August 3, 2007 among Petrohawk Energy Corporation, the successor by way of merger to KCS Energy, Inc., the parties named therein as existing guarantors, the parties named therein as new guarantors, and The Law Debenture Trust Company of New York, as the successor to U.S. Bank National Association, as trustee (Incorporated by reference to Exhibit 4.12 to our Quarterly Report on Form 10-Q filed on November 6, 2008).
4.9	Fifth Supplemental Indenture dated as of November 28, 2008 among Petrohawk Energy Corporation, HK Energy Marketing, LLC, the parties named therein as guarantors, and The Law Debenture Trust Company of New York, as the successor to U.S. Bank National Association, as trustee (Incorporated by reference to Exhibit 4.9 to our Annual Report on Form 10-K filed on February 25, 2009).
4.10	Sixth Supplemental Indenture dated as of January 26, 2009 among Winwell Resources, L.L.C., KCS Resources, LLC, Petrohawk Energy Corporation, the parties named therein as guarantors, and The Law Debenture Trust Company of New York, as the successor to U.S. Bank National Association, as trustee (Incorporated by reference to Exhibit 4.10 to our Annual Report on Form 10-K filed on February 25, 2009).

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Exhibit No	Description
4.11	Indenture dated July 12, 2006 among Petrohawk Energy Corporation, U.S. Bank National Association, as trustee, and the subsidiary guarantors named therein, relating to Petrohawk Energy Corporation s 9 1/8% senior notes due 2013 (Incorporated by reference to Exhibit 4.6 to our Current Report on Form 8-K filed on July 17, 2006).
4.12	First Supplemental Indenture dated July 12, 2006 among Petrohawk Energy Corporation, U.S. Bank National Association, as trustee, and the subsidiary guarantors named therein (Incorporated by reference to Exhibit 4.7 to our Current Report on Form 8-K filed on July 17, 2006).
4.13	Second Supplemental Indenture dated August 3, 2007 among Petrohawk Energy Corporation, One TEC, LLC, One TEC Operating, LLC, Bison Ranch, LLC, the parties named therein as existing guarantors and U.S. Bank National Association, as trustee (Incorporated by reference to Exhibit 4.10 to our Quarterly Report on Form 10-Q filed on November 8, 2007).
4.14	Third Supplemental Indenture dated as of November 28, 2008 among Petrohawk Energy Corporation, HK Energy Marketing, LLC, the parties named therein as guarantors, and U.S. Bank National Association, as trustee (Incorporated by reference to Exhibit 4.14 to our Annual Report on Form 10-K filed on February 25, 2009).
4.15	Fourth Supplemental Indenture dated as of January 26, 2009 among Winwell Resources, L.L.C., KCS Resources, LLC, Petrohawk Energy Corporation, the parties named therein as guarantors, and U.S. Bank National Association, as trustee (Incorporated by reference to Exhibit 4.15 to our Annual Report on Form 10-K filed on February 25, 2009).
4.16	Indenture, dated May 13, 2008, among Petrohawk Energy Corporation, the subsidiary guarantors named therein, and U.S. Bank Trust National Association (Incorporated by reference to Exhibit 4.1 to our Current Report on Form 8-K filed on May 15, 2008).
4.17	First Supplemental Indenture dated as of November 28, 2008 among Petrohawk Energy Corporation, HK Energy Marketing, LLC, and parties named therein as guarantors, and U.S. Bank Trust National Association, as trustee (Incorporated by reference to Exhibit 4.17 to our Annual Report on Form 10-K filed on February 25, 2009).
4.18	Second Supplemental Indenture dated as of January 26, 2009 among Winwell Resources, L.L.C., KCS Resources, LLC, Petrohawk Energy Corporation, the parties named therein as guarantors, and U.S. Bank Trust National Association, as trustee (Incorporated by reference to Exhibit 4.18 to our Annual Report on Form 10-K filed on February 25, 2009).
4.19	Rights Agreement, dated as of October 14, 2008, between Petrohawk Energy Corporation and American Stock Transfer & Trust Company, as Rights Agent (Incorporated by reference to Exhibit 4.1 to our Current Report on Form 8-K filed on October 16, 2008).
4.20	Registration Rights Agreement, dated May 13, 2008, among the Company, the subsidiary guarantors named therein, and Lehman Brothers Inc., on behalf of Lehman Brothers Inc., J.P. Morgan Securities Inc., Merrill Lynch, Pierce, Fenner & Smith Incorporated, BNP Paribas Securities Corp., Credit Suisse Securities (USA) LLC, Banc of America Securities LLC, Citigroup Global Markets Inc., BMO Capital Markets Corp., RBC Capital Markets Corporation, and Wells Fargo Securities, LLC. (Incorporated by reference to Exhibit 4.2 of our Current Report on Form 8-K filed on May 15, 2008).
4.21	Amendment No. 1 to Rights Agreement, dated as of June 10, 2009, between Petrohawk Energy Corporation and American Stock Transfer & Trust Company, LLC, as Rights Agent (Incorporated by reference to Exhibit 4.1 of our Current Report on Form 8-K filed on June 12, 2009).
4.22	Indenture, dated January 27, 2009, among the Company, the subsidiary guarantors named therein, and U.S. Bank Trust National Association (Incorporated by reference to Exhibit 4.1 of our Current Report on Form 8-K filed on January 28, 2009).

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Exhibit No	Description
4.23	Registration Rights Agreement, dated January 27, 2009, among the Company, the subsidiary guarantors named therein, and J.P. Morgan Securities Inc., on behalf of J.P. Morgan Securities Inc., BNP Paribas Securities Corp., Wachovia Capital Markets, LLC, Banc of America Securities LLC, BMO Capital Markets Corp., Barclays Capital Inc., Fortis Securities LLC, Calyon Securities (USA) Inc., RBC Capital Markets Corporation, Capital One Southcoast, Inc., Wedbush Morgan Securities Inc., Natixis Bleichroeder Inc., Citigroup Global Markets Inc., BBVA Securities, Inc., and Piper Jaffray & Co. (Incorporated by reference to Exhibit 4.2 of our Current Report on Form 8-K filed on January 28, 2009).
10.1	Third Amended and Restated 2004 Employee Incentive Plan (Incorporated by reference to Exhibit 10.01 of our Current Report on Form 8-K filed on June 23, 2009).
10.2	Second Amended and Restated 2004 Non-Employee Director Incentive Plan (Incorporated by reference to Exhibit 10.02 of our Current Report on Form 8-K filed on June 23, 2009).
10.3	Agreement of Sale and Purchase by and among Petrohawk Properties, LP, Petrohawk Energy Corporation, KCS Resources, Inc. and One TEC, LLC collectively, as Seller and Milagro Development I, LP as Purchaser dated October 15, 2007 (Incorporated by reference to Exhibit 10.1 of our Current Report on Form 8-K filed on December 7, 2007).
10.4	Third Amended and Restated Senior Revolving Credit Agreement dated September 10, 2008, among Petrohawk Energy Corporation, each of the Lenders from time to time party thereto, BNP Paribas, as administrative agent for the Lenders, Bank of America, N.A, and BMO Capital Markets Financing, Inc., as syndication agents for the Lenders, and JPMorgan Chase Bank, N.A., Wells Fargo Bank, N.A. and Fortis Capital Corp. as co-documentation agents for the Lenders (Incorporated by reference to Exhibit 10.1 of our Current Report on Form 8-K filed on September 15, 2008).
10.5	Third Amended and Restated Guarantee and Collateral Agreement dated September 10, 2008, made by Petrohawk Energy Corporation and each of its subsidiaries, as Grantors, in favor of BNP Paribas, as Administrative Agent (Incorporated by reference to Exhibit 10.2 of our Current Report on Form 8-K filed on September 15, 2008).
12.1*	Computation of Ratio of Earnings to Combined Fixed Charges and Preference Dividends
31.1*	Certificate of Chief Executive Officer under Section 302 of the Sarbanes-Oxley Act of 2002
31.2*	Certificate of Chief Financial Officer under Section 302 of Sarbanes-Oxley Act of 2002
32.1*	Certifications required by Rule 13a-14(b) or Rule 15d-14(b) under the Securities Exchange Act of 1934 and 18 U.S.C. Section 1350
101*	Interactive Data File

* Attached hereto.
Indicates management contract or compensatory plan or arrangement

The registrant has not filed with this report copies of the instruments defining rights of all holders of long-term debt of the registrant and its consolidated subsidiaries based upon the exception set forth in Item 601 (b)(4)(iii)(A) of Regulation S-K. Copies of such instruments will be furnished to the Securities and Exchange Commission upon request.

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SIGNATURES

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

PETROHAWK ENERGY CORPORATION

Date: August 4, 2009

By: /s/ Floyd C. Wilson
Floyd C. Wilson
Chairman of the Board, President and Chief Executive Officer

By: /s/ Mark J. Mize
Mark J. Mize

Executive Vice President, Chief Financial Officer

and Treasurer

By: /s/ C. Byron Charboneau
C. Byron Charboneau

Vice President, Chief Accounting Officer and Controller

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