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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 September 30, 2010

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 incorporation or organization)	**(I.R.S. Employer 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 (§ 232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files). Yes x No ¨

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

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

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

As of October 26, 2010 the Registrant had 302,407,291 shares of Common Stock, $.001 par value, outstanding.

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Special note regarding forward-looking statements

This Quarterly 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, i achievable, anticipate, will, continue, potential, should, could and similar terms and phrases. Although we believe that the expectations in these forward-looking statements are reasonable, they do involve certain assumptions, risks and uncertainties. Actual results could differ materially from those anticipated in these forward-looking statements. One should consider carefully the statements under Risk Factors in this report and in our Annual Report on Form 10-K for the year ended December 31, 2009 and the other disclosures contained herein and therein, which describe factors that could cause our actual results to differ from those anticipated 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 Louisiana, Arkansas and Texas, including our resource-style plays such as the Haynesville, Bossier, Fayetteville and Eagle Ford Shales;
- volatility in commodity prices for oil and natural gas;
- the possibility that our industry may be subject to future regulatory or legislative actions (including any additional taxes and changes in environmental regulation);
- the presence or recoverability of estimated oil and natural gas reserves and the actual future production rates and associated costs;
- the potential for production decline rates for our wells to be 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, fracture stimulation services and tubulars, and access to adequate gathering systems and pipeline take-away capacity, necessary to execute 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 economic recession in the United States will be prolonged, which could adversely affect the demand for oil and natural gas;

- 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 September 30,		Nine Months Ended September 30,	
	2010	2009	2010	2009
Operating revenues:				
Oil and natural gas	$ 280,328	$ 166,683	$ 820,753	$ 492,214
Marketing	122,981	63,155	360,438	216,165
Midstream	5,873	8,100	21,810	20,314
Total operating revenues	409,182	237,938	1,203,001	728,693
Operating expenses:				
Marketing	139,053	66,586	392,984	211,722
Production:				
Lease operating	15,794	20,788	49,573	55,903
Workover and other	2,758	865	6,707	1,793
Taxes other than income	(3,185)	15,204	14,849	39,921
Gathering, transportation and other	50,046	22,743	114,296	65,870
General and administrative	40,425	24,550	115,974	68,181
Depletion, depreciation and amortization	107,812	91,692	315,061	290,383
Full cost ceiling impairment				1,732,486
Total operating expenses	352,703	242,428	1,009,444	2,466,259
Amortization of deferred gain	59,472		123,839	
Income (loss) from operations	115,951	(4,490)	317,396	(1,737,566)
Other income (expenses):				
Net gain (loss) on derivative contracts	147,892	(1,568)	345,970	196,360
Interest expense and other	(110,714)	(58,981)	(235,093)	(170,929)
Equity investment income	8,572		10,619	
Total other income (expenses)	45,750	(60,549)	121,496	25,431
Income (loss) before income taxes	161,701	(65,039)	438,892	(1,712,135)
Income tax (provision) benefit	(63,020)	24,862	(170,581)	650,201
Net income (loss)	$ 98,681	$ (40,177)	$ 268,311	$ (1,061,934)
Net income (loss) per share:				
Basic	$ 0.33	$ (0.14)	$ 0.89	$ (3.88)

Diluted	$ 0.33	$ (0.14)	$ 0.89	$ (3.88)
Weighted average shares outstanding:				
Basic	300,543	287,913	300,377	273,477
Diluted	301,941	287,913	302,541	273,477

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

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PETROHAWK ENERGY CORPORATION

CONDENSED CONSOLIDATED BALANCE SHEETS (Unaudited)

(In thousands, except share and per share amounts)

	September 30, 2010	December 31, 2009
Current assets:		
Cash	$ 4,152	$ 1,511
Accounts receivable	304,794	239,264
Receivables from derivative contracts	275,901	112,441
Receivable from equity affiliate	780	
Prepaids and other	60,838	32,434
Total current assets	646,465	385,650
Oil and natural gas properties (full cost method):		
Evaluated	7,149,602	5,984,765
Unevaluated	2,609,692	2,512,453
Gross oil and natural gas properties	9,759,294	8,497,218
Less accumulated depletion	(4,631,874)	(4,329,485)
Net oil and natural gas properties	5,127,420	4,167,733
Other operating property and equipment:		
Gas gathering systems and equipment	269,494	497,551
Other operating assets	46,725	26,002
Gross other operating property and equipment	316,219	523,553
Less accumulated depreciation	(26,776)	(26,287)
Net other operating property and equipment	289,443	497,266
Other noncurrent assets:		
Goodwill	932,802	932,802
Other intangible assets, net of amortization	92,105	100,395
Debt issuance costs, net of amortization	46,393	44,871
Deferred income taxes	218,330	245,413
Receivables from derivative contracts	94,575	50,421
Restricted cash	42,922	213,704
Equity investment	206,485	
Other	4,555	23,816
Total assets	$ 7,701,495	$ 6,662,071
Current liabilities:		
Accounts payable and accrued liabilities	$ 762,600	$ 633,171
Deferred income taxes	74,100	14,484
Liabilities from derivative contracts	683	1,807

Long-term debt	25,199	49,370
Total current liabilities	862,582	698,832
Long-term debt	2,593,062	2,592,544
Other noncurrent liabilities:		
Liabilities from derivative contracts	1,773	
Asset retirement obligations	32,471	44,000
Deferred gain on sale	595,516	
Other	514	3,023
Commitments and contingencies (Note 7)		
Stockholders equity:		
Common stock: 500,000,000 shares of $.001 par value authorized; 302,385,280 and 301,194,695 shares issued and outstanding at September 30, 2010 and December 31, 2009, respectively	302	301
Additional paid-in capital	4,623,257	4,599,664
Accumulated deficit	(1,007,982)	(1,276,293)
Total stockholders equity	3,615,577	3,323,672
Total liabilities and stockholders equity	$ 7,701,495	$ 6,662,071

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

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PETROHAWK ENERGY CORPORATION

CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS (Unaudited)

(In thousands)

	Nine Months Ended September 30, 2010	2009
Cash flows from operating activities:		
Net income (loss)	$ 268,311	$ (1,061,934)
Adjustments to reconcile net income (loss) to net cash provided by operating activities:		
Depletion, depreciation and amortization	315,061	290,383
Full cost ceiling impairment		1,732,486
Income tax provision (benefit)	170,581	(650,201)
Stock-based compensation	17,038	10,762
Net unrealized (gain) loss on derivative contracts	(190,228)	96,752
Amortization of deferred gain	(123,839)	
Equity investment income	(10,619)	
Distributions from equity affiliate	13,190	
Other operating	75,098	15,926
Change in assets and liabilities:		
Accounts receivable	(136,655)	91,571
Receivable from equity affiliate	(780)	
Prepaids and other	(28,530)	(2,016)
Accounts payable and accrued liabilities	(22,967)	(49,448)
Other	16,752	469
Net cash provided by operating activities	362,413	474,750
Cash flows from investing activities:		
Oil and natural gas capital expenditures	(1,731,707)	(1,164,392)
Proceeds received from sale of oil and natural gas properties	613,317	724
Proceeds received from sale of Haynesville gas gathering systems	921,408	
Marketable securities purchased	(1,091,005)	(1,282,601)
Marketable securities redeemed	1,091,005	1,255,582
Increase in restricted cash	(198,209)	
Decrease in restricted cash	368,991	
Other operating property and equipment capital expenditures	(212,137)	(225,322)
Other intangible assets acquired		(105,108)
Contributions to equity affiliate	(10,974)	
Other		37,600
Net cash used in investing activities	(249,311)	(1,483,517)
Cash flows from financing activities:		
Proceeds from exercise of stock options and warrants	1,821	2,667
Proceeds from issuance of common stock		956,500
Offering costs		(30,727)
Proceeds from borrowings	2,184,000	937,674
Repayment of borrowings	(2,274,888)	(849,513)
Debt issuance costs	(17,706)	(13,025)
Other	(3,688)	

Net cash (used in) provided by financing activities		(110,461)		1,003,576
Net increase (decrease) in cash		2,641		(5,191)
Cash at beginning of period		1,511		6,883
Cash at end of period	$	4,152	$	1,692

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

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PETROHAWK ENERGY CORPORATION

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS (Unaudited)

1. FINANCIAL STATEMENT PRESENTATION

Petrohawk Energy Corporation (Petrohawk or the Company) is an independent oil and natural gas company engaged in the exploration, development and production of predominately natural gas properties located onshore in the United States. The Company operates in two segments, oil and natural gas production and midstream operations. The unaudited condensed consolidated financial statements include the accounts of all majority-owned, controlled subsidiaries. The Company uses the equity method to account for investments in which the Company does not have a majority interest, but does have significant influence. All intercompany accounts and transactions have been eliminated. 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 the results of operations for, the periods presented. During interim periods, Petrohawk follows the accounting policies disclosed in its 2009 Annual Report on Form 10-K, filed with the United States Securities and Exchange Commission (SEC). Please refer to the footnotes in the 2009 Annual Report on Form 10-K when reviewing interim financial results.

Use of Estimates

The preparation of the Company s unaudited condensed consolidated financial statements in conformity with accounting principles generally accepted in the United States requires the Company s management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities, if any, at the date of the unaudited condensed consolidated financial statements and the reported amounts of revenues and expenses during the respective reporting periods. The Company bases its estimates and judgments on historical experience and on various other assumptions and information that are believed to be reasonable under the circumstances. Estimates and assumptions about future events and their effects cannot be perceived with certainty and, accordingly, these estimates may change as new events occur, as more experience is acquired, as additional information is obtained and as the Company s operating environment changes. Actual results may differ from the estimates and assumptions used in the preparation of the Company s unaudited condensed consolidated financial statements.

Interim period results are not necessarily indicative of results of operations or cash flows for the full year and accordingly, certain information normally included in financial statements prepared in accordance with accounting principles generally accepted in the United States has been condensed or omitted. The Company has evaluated events or transactions through the date of issuance of these unaudited condensed consolidated financial statements.

Marketing Revenue and Expense

A subsidiary of the Company purchases and sells its own and third party natural gas produced from wells which the Company and third parties operate. 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.

Midstream Revenues

Revenues from the Company s midstream operations are derived from providing gathering and treating services for the Company and other owners in wells which the Company and third parties operate. Revenues are recognized when services are provided at a fixed or determinable price, collectability is reasonably assured and evidenced by a contract. The midstream segment does not take title to the natural gas for which services are provided, with the exception of imbalances that are monthly cash settled. The imbalances are recorded using published natural gas market prices.

Severance Tax Refunds

The Company records severance tax refunds when collectability is assured and the appropriate taxing authorities have notified the Company that its request for a refund has been approved. Severance tax refunds are included in *Taxes other than income* on the unaudited condensed consolidated statements of operations.

Risk Management Activities

The Company follows Accounting Standards Codification (ASC) 815, *Derivatives and Hedging*. From time to time, the Company may hedge a portion of its forecasted oil, natural gas and natural gas liquids 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 unaudited condensed consolidated statements of operations.

Gas Gathering Systems and Equipment and Other Operating Assets

Gas gathering systems and equipment are recorded at cost. Depreciation is calculated using the straight-line method over a 30-year estimated useful life. Upon disposition, the cost and accumulated depreciation are removed and any gains or losses are reflected in current operations. Maintenance and repair costs are charged to operating expense as incurred. Material expenditures that increase the life of an asset are capitalized and depreciated over the estimated remaining useful life of the asset. The Company capitalized $0.4 million and $2.9 million of interest for the three and nine months ended September 30, 2010, respectively, related to the construction of the Company s gas gathering systems and equipment. The Company capitalized $0.8 million and $3.3 million of interest for the three and nine months ended September 30, 2009, respectively.

Gas gathering systems and equipment as of September 30, 2010 and December 31, 2009 consisted of the following:

	September 30, 2010(1)	December 31, 2009
	(In thousands)	
Gas gathering systems and equipment	$ 269,494	$ 497,551
Less accumulated depreciation	(12,171)	(14,618)
Net gas gathering systems and equipment	$ 257,323	$ 482,933

(1) On May 21, 2010, the Company contributed its Haynesville Shale gas gathering and treating business for a 50% membership interest in a new joint venture entity, KinderHawk Field Services LLC, and approximately $921 million in cash. See Note 2, *Acquisitions and Divestitures* for more details.

Other operating assets are recorded at cost. Depreciation is calculated using the straight-line method over the following estimated useful lives: automobiles, leasehold improvements, furniture and equipment, five years or the lesser of lease term; rental equipment, seven years; and computers, three years. Upon disposition, the cost and accumulated depreciation are removed and any gains or losses are reflected in current operations. Maintenance and repair costs are charged to operating expense as incurred. Material expenditures that increase the life of an asset are capitalized and depreciated over the estimated remaining useful life of the asset.

The Company reviews its gas gathering systems and equipment and other operating assets in accordance with ASC 360, *Property, Plant, and Equipment* (ASC 360). ASC 360 requires the Company to evaluate gas gathering systems and equipment and other operating assets as events occur or circumstances change that would more likely than not reduce the fair value below the carrying amount. If the carrying amount is not recoverable from its undiscounted cash flows, then the Company would recognize an impairment loss for the difference between the carrying amount and the current fair value. Further, the Company evaluates the remaining useful lives of its gas gathering systems and equipment and other operating assets at each reporting period to determine whether events and circumstances warrant a revision to the remaining depreciation periods.

Equity Method Investment

On May 21, 2010, the Company contributed its Haynesville Shale gas gathering and treating business for a 50% membership interest in a new joint venture entity, KinderHawk Field Services LLC (KinderHawk), and approximately $921 million in cash. The Company s investment in KinderHawk, in which the Company does not have a majority interest, but does have significant influence, is accounted for under the equity method of accounting. Under the equity method of accounting, the Company s share of net income (loss) from KinderHawk is reflected as an increase (decrease) in its investment account in *Other noncurrent assets* and is also recorded as equity investment income (loss) in *Other income (expenses).* Distributions from KinderHawk are recorded as reductions of the Company s investment and contributions to KinderHawk are recorded as increases of the Company s investment. The Company reviews its equity method investment for potential impairment whenever events or changes in circumstances indicate that an other-than-temporary decline in the value of the investment has occurred. See Note 13, *Equity Method Investment*, for further discussion.

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. ASC 350, *Intangibles Goodwill and Other* requires that intangible assets with indefinite lives, including goodwill, be evaluated on an annual basis for impairment or more frequently if events occur 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. The Company has determined that it has two reporting units: oil and natural gas production and midstream operations. All of the Company s goodwill has been allocated to its oil and natural gas production reporting unit as all of its historical goodwill relates to its acquisitions of oil and natural gas properties. The Company completed its annual goodwill impairment test during the third quarter of 2010 and no goodwill impairment was deemed necessary.

Other Intangible Assets

The Company treats the costs associated with transportation contracts acquired in the third quarter of 2009 as other intangible assets. The initial amount recorded represents the fair value of the contract at the time of acquisition, which is amortized using the straight-line method over the life of the contract. Any unamortized balance of the Company s other intangible assets is subject to impairment testing pursuant to the *Impairment or Disposal of Long-Lived Assets Subsections* of ASC Subtopic 360-10.

Amortization expense was $2.8 million and $8.3 million for the three and nine months ended September 30, 2010, respectively, and was allocated to operating expenses between *Marketing* and *Gathering, transportation and other* on the unaudited condensed consolidated statements of operations based on the usage of the contract. Amortization expense for the three and nine months ended September 30, 2009, was $1.8 million. The estimated amortization expense will be approximately $11.1 million per year for the remainder of the contract through 2019.

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Other intangible assets subject to amortization at September 30, 2010 and December 31, 2009 are as follows:

	September 30, 2010	December 31, 2009
	(In thousands)	
Transportation contracts	$ 105,108	$ 105,108
Less accumulated amortization	(13,003)	(4,713)
Net transportation contracts	$ 92,105	$ 100,395

Recently Issued Accounting Pronouncements

In January 2010, the Financial Accounting Standards Board (FASB) issued Accounting Standards Update (ASU) No. 2010-06, *Improving Disclosures about Fair Value Measurements* (ASU 2010-06). This update provides amendments to Subtopic 820-10 and requires new disclosures for 1) significant transfers in and out of Level 1 and Level 2 and the reasons for such transfers and 2) activity in Level 3 fair value measurements to show separate information about purchases, sales, issuances and settlements. In addition, this update amends Subtopic 820-10 to clarify existing disclosures around the disaggregation level of fair value measurements and disclosures for the valuation techniques and inputs utilized (for Level 2 and Level 3 fair value measurements). The provisions in ASU 2010-06 are applicable to interim and annual reporting periods beginning subsequent to December 15, 2009, with the exception of Level 3 disclosures of purchases, sales, issuances and settlements, which will be required in reporting periods beginning after December 15, 2010. The adoption of ASU 2010-06 did not impact the Company s operating results, financial position or cash flows, but did impact the Company s disclosures on fair value measurements. See Note 5, *Fair Value Measurements.*

In April 2010, the FASB issued ASU No. 2010-12, *Accounting for Certain Tax Effects of the 2010 Health Care Reform Acts* (ASU 2010-12). This update clarifies questions surrounding the accounting implications of the different signing dates of the Health Care and Education Reconciliation Act (signed March 30, 2010) and the Patient Protection and Affordable Care Act (signed March 23, 2010). ASU 2010-12 states that the FASB and the Office of the Chief Accountant at the SEC would not be opposed to view the two Acts together for accounting purposes. The adoption of ASU 2010-12 did not impact the Company s operating results, financial position, cash flows or disclosures.

2. ACQUISITIONS AND DIVESTITURES

Acquisitions

Kaiser Trading, LLC

On July 31, 2009, the Company purchased all outstanding membership interests in Kaiser Trading, LLC (Kaiser), now known as HK Transportation, LLC, for approximately $105 million. Kaiser s only assets were transportation-related contracts including a firm transportation contract, interruptible gas transportation service agreement, parking and lending services agreement, and a pooling services agreement. The initial firm transportation contract runs through 2013 and at no additional cost, the Company has the contractual right to extend firm supply through 2019.

Divestitures

Permian Basin Properties

On October 30, 2009, the Company sold its Permian Basin properties for $376 million in cash, before customary closing adjustments. The effective date of the sale was July 1, 2009. Proceeds from the sale were recorded as a reduction to the carrying value of the Company s full cost pool with no gain or loss recorded.

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West Edmond Hunton Lime Unit

On April 30, 2010, the Company completed the sale of its interest in the West Edmond Hunton Lime Unit (WEHLU) Field in Oklahoma County, Oklahoma for $155 million in cash, before customary closing adjustments. Proceeds from the sale were recorded as a reduction to the carrying value of the Company s full cost pool with no gain or loss recorded. The transaction had an effective date of April 1, 2010. In conjunction with the closing, the Company assigned five natural gas swaps and five crude oil swaps to one of the purchasers.

Terryville

On May 12, 2010, the Company completed the sale of its interest in Terryville Field, located in Lincoln and Claiborne Parishes, Louisiana for $320 million in cash, before customary closing adjustments. Proceeds from the sale were recorded as a reduction to the carrying value of the Company s full cost pool with no gain or loss recorded. The transaction had an effective date of January 1, 2010. In conjunction with the closing, the Company deposited $75 million with a qualified intermediary to facilitate like-kind exchange transactions. At September 30, 2010, the Company had $42.9 million remaining for use in future acquisitions.

Hawk Field Services, LLC Joint Venture

On May 21, 2010, Hawk Field Services, LLC (HFS), a wholly owned subsidiary of Petrohawk and KM Gathering LLC (Kinder Morgan), an affiliate of Kinder Morgan Energy Partners, L.P., a publicly traded master limited partnership, formed a new joint venture pursuant to a Formation and Contribution Agreement (Contribution Agreement). The new joint venture entity, KinderHawk Field Services LLC (KinderHawk), engages in the natural gas midstream business in Northwest Louisiana, focused on the Haynesville Shale formation. Pursuant to the Contribution Agreement, HFS contributed to KinderHawk its Haynesville Shale gathering and treating business in Northwest Louisiana, and Kinder Morgan contributed approximately $921 million in cash ($875 million for a 50% membership interest in KinderHawk and $46 million for certain closing adjustments including 2010 capital expenditures through the closing date) to KinderHawk. Each of HFS and Kinder Morgan own a 50% membership interest in KinderHawk. KinderHawk distributed the approximate $921 million to HFS. The joint venture has an economic effective date of January 1, 2010, and HFS continued to operate the business until September 30, 2010, at which date HFS and Kinder Morgan terminated the transition services agreement and KinderHawk assumed operations of the joint venture. The Company accounts for its interest in KinderHawk under the equity method of accounting.

The Company is obligated to deliver minimum annual quantities of natural gas to KinderHawk equal to 50% of the Company s annual projected production from Petrohawk operated wells located on certain dedicated acreage from the Haynesville and Bossier Shales in Northwest Louisiana for the next five years, or in the alternative, pay an annual true-up fee to KinderHawk if such minimum annual quantities are not delivered. The Company pays KinderHawk negotiated gathering and treating fees, subject to an annual inflation adjustment factor. The gathering fee is equal to $0.34 per thousand cubic feet (Mcf) of natural gas delivered at KinderHawk s receipt points. The treating fee is charged for gas delivered containing more than 2% by volume of carbon dioxide. For gas delivered containing between 2% and 5.5% carbon dioxide, the treating fee is between $0.030 and $0.345 per Mcf, and for gas containing over 5.5% carbon dioxide, the treating fee starts at $0.365 per Mcf and increases on a scale of $0.09 per Mcf for each additional 1% of carbon dioxide content.

Mid-Continent Properties

On September 29, 2010, the Company completed the sale of its interest in certain Mid-Continent properties in Texas, Oklahoma and Arkansas for $123 million in cash, before customary closing adjustments. Proceeds from the sale were recorded as a reduction to the carrying value of the Company s full cost pool with no gain or loss recorded. The transaction had an effective date of July 1, 2010.

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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. Beginning December 31, 2009, full cost companies use the unweighted arithmetic average first day of the month price for oil and natural gas for the 12-month period preceding the calculation date to calculate the future net revenues of proved reserves. Prior to December 31, 2009, companies used the price in effect at the calculation date and had the option, under certain circumstances, to elect to use subsequent commodity prices if they increased after the calculation date.

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 September 30, 2010, the ceiling test value of the Company s reserves was calculated based on the first day average of the twelve months ended September 30, 2010 of the West Texas Intermediate (WTI) posted price of $75.55 per barrel, adjusted by lease for quality, transportation fees, and regional price differentials, and the first day average of the twelve months ended September 30, 2010 of the Henry Hub price of $4.41 per million British thermal units (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 at September 30, 2010 did not exceed the ceiling amount. Changes in production rates, levels of reserves, future development costs, and other factors will determine the Company s ceiling test calculation and impairment analyses in future periods.

At December 31, 2009, the Company s net book value of oil and natural gas properties exceeded the ceiling amount based on the unweighted arithmetic average of the first day of each month for the 12-month period ended December 31, 2009 WTI posted price of $57.65 per barrel and the unweighted arithmetic average of the first day of each month for the 12-month period ended December 31, 2009 of the Henry Hub price of $3.87 per Mmbtu. As a result, the Company recorded a full cost ceiling impairment before income taxes of approximately $106 million and $65 million after income taxes.

At September 30, 2009, the ceiling test value of the Company s reserves was calculated based on the September 30, 2009 WTI posted price of $70.61 per barrel, adjusted by lease for quality, transportation fees, and regional price differentials, and the September 30, 2009 Henry Hub spot market price of $3.30 per Mmbtu, adjusted by lease for energy content, transportation fees, and regional price differentials. At September 30, 2009, the Company s net book value of oil and natural gas properties exceeded the ceiling amount by approximately $880 million before income taxes, $546 million after income taxes. However, subsequent to September 30, 2009, the market price for Henry Hub gas and WTI oil increased significantly. As a consequence, prior to October 28, 2009, the Company elected to use prices on October 28, 2009, which were a WTI price of $77.20 per barrel and a Henry Hub spot market price of $4.51 per Mmbtu, adjusted for certain items as previously discussed. Utilizing these prices, the Company s net book value of oil and natural gas properties at September 30, 2009, would not have exceeded the ceiling amount. As a result of the increase in the ceiling amount using the subsequent prices, the Company did not record a write-down of its oil and natural gas property costs.

4. DEBT

Long-term debt as of September 30, 2010 and December 31, 2009 consisted of the following:

	September 30, 2010(1)	December 31, 2009(1)
	(In thousands)	
Senior revolving credit facility	$ 129,000	$ 203,000
7.25% $825 million senior notes (2)	825,000	
10.5% $600 million senior notes (3)	560,056	554,154
7.875% $800 million senior notes	800,000	800,000
9.125% $775 million senior notes (4)		764,694
7.125% $275 million senior notes (5)	268,273	266,402
9.875% senior notes		224
Deferred premiums on derivatives	10,733	4,070
	$ 2,593,062	$ 2,592,544

(1) Amount excludes $25.0 million and $49.4 million of deferred premiums on derivatives which have been classified as current at September 30, 2010 and December 31, 2009, respectively. Amount excludes $0.2 million of 9.875% Senior Notes due 2011 which have been classified as current at September 30, 2010.

(2) The 7.25% $825 million senior notes due 2018 were issued in the third quarter of 2010 to fund the repurchase of the 9.125% $775 million senior notes, which were due in 2013. See 7.25% Senior Notes below for further details.

(3) Amount includes a $39.9 million and $45.8 million discount at September 30, 2010 and December 31, 2009, respectively, recorded by the Company in conjunction with the issuance of the $600 million senior notes. See 10.5% Senior Notes below for more details.

(4) The 9.125% senior notes were repurchased during the third quarter of 2010. See 9.125% Senior Notes below for more details.

(5) Amount includes a $4.1 million and $6.0 million discount at September 30, 2010 and December 31, 2009, 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

Effective August 2, 2010, the Company amended and restated its existing credit facility dated October 14, 2009 by entering into the Fifth Amended and Restated Senior Revolving Credit Agreement, dated as of August 2, 2010 (the Senior Credit Agreement), among 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 Bank of Montreal as co-syndication agents for the Lenders, and JPMorgan Chase Bank, N.A. and Wells Fargo Bank, N.A., as co-documentation agents for the Lenders. The Senior Credit Agreement provides for a $2.0 billion facility. As of September 30, 2010, the borrowing base was approximately $1.1 billion, $1.0 billion of which related to the Company s oil and natural gas properties and up to $100 million (currently limited as described below) related to the Company s midstream assets. The portion of the borrowing base relating to the Company s oil and natural gas properties 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 component of the borrowing base relating to the Company s midstream assets is limited to the lesser of $100 million or 3.5 times midstream EBITDA, and is calculated quarterly. As of September 30, 2010, the midstream component of the borrowing base was limited to approximately $53 million based on midstream EBITDA. 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.

Amounts outstanding under the Senior Credit Agreement bear interest at specified margins over the London Interbank Offered Rate (LIBOR) of 2.00% to 3.00% for Eurodollar loans or at specified margins over the Alternate Base Rate (ABR) of 1.00% to 2.00% for ABR loans. Such margins will fluctuate based on the utilization of the facility. Borrowings under the Senior Credit Agreement are secured by first priority liens on substantially all of the Company s assets, including pursuant to the terms of the Fifth Amended and Restated Guarantee and Collateral Agreement, all of the assets of, and equity interests in, the Company s subsidiaries. Amounts drawn down on the facility will mature on July 1, 2014.

The Senior Credit Agreement contains customary 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 (as defined in the Senior Credit Agreement) 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 September 30, 2010, the Company was in compliance with its financial debt covenants under the Senior Credit Agreement.

7.25% Senior Notes

On August 3, 2010, the Company entered into a purchase agreement (the Purchase Agreement) with Barclays Capital Inc., on behalf the initial purchasers named therein (the Initial Purchasers), in which the Company agreed to issue and sell $825 million aggregate principal amount of the Company s 7.25% Senior Notes due 2018 (the 2018 Notes) to the Initial Purchasers at a purchase price of 100% of the principal amount of the 2018 Notes. The closing of the sale of the 2018 Notes occurred on August 17, 2010.

In connection with the sale of the 2018 Notes, the Company entered into a Registration Rights Agreement, dated August 17, 2010, among the Company and the Initial Purchasers (the Registration Rights Agreement). Pursuant to the Registration Rights Agreement, the Company agreed to conduct a registered exchange offer for the 2018 Notes or cause to become effective a shelf registration statement providing for the resale of the 2018 Notes. The Company is required to: (i) file an exchange offer registration statement (the Registration Statement) on or prior to 90 days after August 17, 2010, and (ii) use reasonable best efforts to cause such Registration Statement to become effective on or prior to 270 days after August 17, 2010. If the exchange offer is not consummated within 310 days after August 17, 2010, or upon the occurrence of certain other contingencies, the Company agreed to file a shelf registration statement to cover resales of the 2018 Notes by holders who satisfy certain conditions relating to the provision of information in connection with the shelf registration statement. If the Company fails to comply with certain obligations under the Registration Rights Agreement, it will be required to pay liquidated damages in the form of additional cash interest to the holders of the 2018 Notes. The registration statement for the exchange offer became effective on September 29, 2010.

The 2018 Notes bear interest at a rate of 7.25% per annum, payable semi-annually on February 15 and August 15 of each year, commencing on February 15, 2011. The 2018 Notes will mature on August 15, 2018. The 2018 Notes are senior unsecured obligations of the Company and rank equally with all of its current and future senior indebtedness. The 2018 Notes are jointly and severally, fully and unconditionally guaranteed on a senior unsecured basis by the Company s subsidiaries. Petrohawk Energy Corporation, the issuer of the 2018 Notes, has no material independent assets or operations apart from the assets and operations of its subsidiaries.

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 of its 10.5% senior notes due 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 bear interest at a rate of 10.5% per annum, payable semi-annually on February 1 and August 1 of each year. 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, fully and unconditionally guaranteed on a senior unsecured basis by the Company s subsidiaries. Petrohawk Energy Corporation, the issuer of the 2014 Notes, has no material independent assets or operations apart from the assets and operations of its subsidiaries.

In conjunction with the issuance of the 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 $39.9 million at September 30, 2010.

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. 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, fully and unconditionally 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.

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 Company issued the 2013 Notes in two tranches, $650 million on July 12, 2006 and $125 million on July 27, 2006. The $650 million tranche of 2013 Notes were issued at 98.735% of the face amount. The additional $125 million of 2013 Notes were issued pursuant to the same Indenture at 101.125% 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. 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, fully and unconditionally guaranteed on a senior unsecured basis by the Company s subsidiaries. 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.

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 zero at September 30, 2010. 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 zero at September 30, 2010.

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Upon issuance of the 2018 Notes, as discussed above, on August 3, 2010, the Company commenced a cash tender offer for any and all of the outstanding of the 2013 Notes and a solicitation of consents to amend the indenture governing the 2013 Notes (the 2013 Notes Indenture). On August 17, 2010, the Company announced that it had received the requisite consents to amend the 2013 Notes Indenture, and the Company entered into the Sixth Supplemental Indenture, dated August 17, 2010, with U.S. Bank National Association, as Trustee for the 2013 Notes. The Sixth Supplemental Indenture eliminated or made less restrictive the most restrictive covenants contained in the 2013 Notes Indenture, including those with respect to SEC reporting, incurrence of indebtedness, distributions to stockholders, creation of liens, assets sales, transactions with affiliates, business activities, change of control, payment of taxes and business combinations. The amendments contained in the Sixth Supplemental Indenture became effective on August 17, 2010 when the Company accepted and redeemed the tendered 2013 Notes.

On August 16, 2010, tenders and consents had been received from holders of $652.7 million in aggregate principal amount of the 2013 Notes, representing approximately 85% of the outstanding 2013 Notes. On August 17, 2010, the Company accepted the 2013 Notes that had been tendered and utilized approximately $689.5 million in net proceeds from the sale of the 2018 Notes to redeem such 2013 Notes. Approximately $116.0 million in aggregate principal amount of 2013 Notes were not tendered.

On August 19, 2010, the Company elected to exercise its right under the 2013 Notes Indenture to redeem effective on September 20, 2010 (the Redemption Date) the remaining $116.0 million aggregate principal amount of the outstanding 2013 Notes at a redemption price of 104.563% of the principal amount thereof (the Redemption Price), plus accrued and unpaid interest on the 2013 Notes redeemed to, but not including, the Redemption Date. Holders of the 2013 Notes were paid the Redemption Price upon presentation and surrender of their 2013 Notes for redemption to the Trustee.

As a result of the early redemption of the 2013 Notes, the Company incurred charges of approximately $47.1 million in the third quarter of 2010. These charges are recorded within *Interest expense and other* on the unaudited condensed consolidated statements of operations.

7.125% Senior Notes

On July 12, 2006, the date of the Company s merger with KCS Energy, Inc. (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. Interest on the 2012 Notes is payable semi-annually, on each April 1 and October 1. The 2012 Notes are jointly and severally, fully and unconditionally guaranteed on a senior unsecured basis by the Company s subsidiaries. Petrohawk Energy Corporation, the issuer of the 2012 Notes, has no material independent assets or operations apart from the assets and operations of its subsidiaries.

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 $4.1 million at September 30, 2010.

9.875% Senior Notes

On April 8, 2004, Mission Resources Corporation (Mission) issued $130 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 repurchased substantially all of the 2011 Notes for face value plus a premium of $14.9 million and accrued interest of $3.5 million. Approximately

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$0.2 million of the notes were not repurchased and remain outstanding and classified as current as of September 30, 2010. In connection with the extinguishment of substantially all of the 2011 Notes, the Company requested and received from the noteholders consent to eliminate the debt covenants associated with the 2011 Notes.

Debt Issuance Costs

The Company capitalizes certain direct costs associated with the issuance of long-term debt. During the third quarter of 2010, the Company capitalized $16.7 million associated with its issuance of the 2018 Notes. The Company expensed $8.3 million of debt issuance costs as a result of the 2013 Note redemption and the reduction in the Senior Credit Agreement s borrowing base. At September 30, 2010 and December 31, 2009, the Company had approximately $46.4 million and $44.9 million, respectively, of debt issuance costs remaining that are being amortized over the lives of the respective debt.

5. FAIR VALUE MEASUREMENTS

Pursuant to ASC 820, *Fair Value Measurements and Disclosures* (ASC 820) 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 unaudited condensed consolidated balance sheets, but also the impact of the Company s nonperformance risk on its liabilities. ASC 820 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.

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 September 30, 2010 and December 31, 2009. As required by ASC 820, 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. There were no transfers between fair value hierarchy levels for the three and nine months ended September 30, 2010.

	September 30, 2010			
	Level 1	**Level 2**	**Level 3**	**Total**
	(In thousands)			
Assets:				
Restricted cash	$ 42,922	$	$	$ 42,922
Receivables from derivative contracts		370,476		370,476
	$ 42,922	$ 370,476	$	$ 413,398
Liabilities:				
Liabilities from derivative contracts	$	$ 2,456	$	$ 2,456

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	December 31, 2009			
	Level 1	Level 2	Level 3	Total
	(In thousands)			
Assets:				
Restricted cash	$ 213,704	$	$	$ 213,704
Receivables from derivative contracts		162,862		162,862
	$ 213,704	$ 162,862	$	$ 376,566
Liabilities:				
Liabilities from derivative contracts	$	$ 1,807	$	$ 1,807

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

Derivatives listed above include collars, swaps, and put options 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 unaudited 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 implied volatility factors related to changes in the forward curves.

As of September 30, 2010 and December 31, 2009, 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.

The following disclosure of the estimated fair value of financial instruments is made in accordance with the requirements of ASC 825, *Financial Instruments*. 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, long-term debt instruments as of September 30, 2010 and December 31, 2009 (excluding premiums and discounts and any amounts that have been classified as current):

	September 30, 2010		December 31, 2009	
Debt	Carrying Amount	Estimated Fair Value	Carrying Amount	Estimated Fair Value
	(In thousands)			
7.25% $825 million senior notes	$ 825,000	$ 840,139	$	$
10.5% $600 million senior notes	600,000	678,000	600,000	658,500
7.875% $800 million senior notes	800,000	846,000	800,000	804,000
9.125% $775 million senior notes			768,725	805,239
7.125% $275 million senior notes	272,375	273,056	272,375	273,056
9.875% senior notes			224	227
	$ 2,497,375	$ 2,637,195	$ 2,441,324	$ 2,541,022

The fair values of the Company s fixed interest debt instruments were calculated using quoted market prices based on trades of such debt as of September 30, 2010 and December 31, 2009.

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6. ASSET RETIREMENT OBLIGATIONS

For wells drilled, 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 and equipment, 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 unaudited condensed consolidated balance sheets and capitalizes the cost in *Oil and natural gas properties* or *Gas gathering systems and equipment* during the period in which the obligation is incurred. The Company records the accretion of its ARO liabilities in *Depletion, depreciation and amortization* expense in the unaudited 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 nine months ended September 30, 2010 (in thousands):

Liability for asset retirement obligation as of December 31, 2009	$ 44,000
Liabilities settled and divested [(1)]	(20,316)
Additions	7,231
Acquisitions	28
Accretion expense	1,528
Liability for asset retirement obligation as of September 30, 2010	$ 32,471

(1) Refer to Note 2, *Acquisitions and Divestitures* for more details on the Company s divestiture activities.

7. COMMITMENTS AND CONTINGENCIES

Commitments

The Company leases corporate office space in Houston, Texas and Tulsa, Oklahoma as well as a number of other field office locations. In addition, the Company has lease commitments related to certain vehicles, machinery and equipment under long-term operating leases. Rent expense was $4.7 million and $3.8 million for the nine months ended September 30, 2010 and 2009, respectively.

As of September 30, 2010, the Company had the following commitments:

	Total Obligation Amount[(1)] (In thousands)	Years Remaining
Natural gas transportation commitments	$ 1,942,209	19
Drilling rig commitments	209,923	2
Non-cancelable operating leases	31,888	9
Pipeline and well equipment obligations	139,744	2
Various contractual commitments (including, among other things, rental equipment obligations and obtaining and processing seismic data)	18,632	3
Total commitments	$ 2,342,396	

(1) On May 21, 2010, the Company created a new joint venture with Kinder Morgan, KinderHawk, which engages in the natural gas midstream business in Northwest Louisiana, focused on the Haynesville Shale formation. As part of this transaction, the Company is committed to contribute up to an additional $105.4 million as of September 30, 2010, in capital during 2010 and 2011 in the event KinderHawk requires capital to finance its planned capital expenditures. This obligation is not reflected in the amounts shown in the above table. In addition, the Company is obligated to deliver minimum annual quantities of natural gas to KinderHawk equal to 50% of the Company s annual projected production from Petrohawk

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operated wells located on certain dedicated acreage from the Haynesville and Bossier Shales in North Louisiana for the next five years, or in the alternative, pay an annual true-up fee to KinderHawk if such minimum annual quantities are not delivered. The Company pays to KinderHawk negotiated gathering and treating fees, subject to an annual inflation adjustment factor. See Note 2, *Acquisitions and Divestitures* for more details.

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. Provisions are established for contingent liabilities when it is probable that a liability has been incurred and the amount is reasonably estimable. 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.

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 the Company s exposure to price fluctuations and reduce the variability in the Company s cash flows associated with anticipated sales of future oil, natural gas and natural gas liquids production. The Company generally hedges a substantial, but varying, portion of anticipated oil, natural gas and natural gas liquids production for the next 12 to 36 months. Derivatives are carried at fair value on the unaudited condensed consolidated balance sheets, with the changes in the fair value included in the unaudited condensed consolidated statements of operations for the period in which the change occurs. Historically, the Company has also entered 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 and may do so at some point in the future as situations present themselves.

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 September 30, 2010, the Company has entered into commodity collars, swaps, and put options. 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 unaudited condensed consolidated statements of operations.

At September 30, 2010, the Company had 118 open commodity derivative contracts summarized in the tables below: 84 natural gas collar arrangements, one natural gas swap arrangement, ten natural gas put options, 17 crude oil collar arrangements, two crude oil swap arrangements, and four natural gas liquids swaps (all four of which were ethane swaps). Derivative commodity contracts settle based on NYMEX WTI and Henry Hub prices which may differ from the actual price received by the Company for the sale of its oil, natural gas and natural gas liquids production.

At December 31, 2009, the Company had 77 open commodity derivative contracts summarized in the tables below: 61 natural gas collar arrangements, one natural gas swap arrangement, 13 natural gas put options and two crude oil swap arrangements.

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All derivative contracts are recorded at fair market value in accordance with ASC 815 and ASC 820 and included in the unaudited condensed consolidated balance sheets as assets or liabilities. The following table summarizes the location and fair value amounts of all derivative contracts in the unaudited condensed consolidated balance sheets as of September 30, 2010 and December 31, 2009:

	Asset derivative contracts			Liability derivative contracts		
Derivatives not designated as hedging contracts under ASC 815	**Balance sheet location**	**September 30, 2010**	**December 31, 2009**	**Balance sheet location**	**September 30, 2010**	**December 31, 2009**
		(In thousands)			**(In thousands)**	
Commodity contracts	Current assets receivables from derivative contracts	$ 275,901	$ 112,441	Current liabilities liabilities from derivative contracts	$ (683)	$ (1,807)
Commodity contracts	Other noncurrent assets receivables from derivative contracts	94,575	50,421	Other noncurrent liabilities liabilities from derivative contracts	(1,773)	
Total derivatives not designated as hedging contracts under ASC 815		$ 370,476	$ 162,862		$ (2,456)	$ (1,807)

The following table summarizes the location and amounts of the Company s realized and unrealized gains and losses on derivative contracts in the Company s unaudited condensed consolidated statements of operations:

Derivatives not designated as hedging contracts under ASC 815	**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 September 30, 2010**	**2009**	**Amount of gain or (loss) recognized in income on derivative contracts nine months ended September 30, 2010**	**2009**
		(In thousands)		**(In thousands)**	
Commodity contracts:					
Unrealized gain (loss) on commodity contracts	Other income (expenses) net gain (loss) on derivative contracts	$ 87,557	$ (112,891)	$ 190,228	$ (96,752)
Realized gain on commodity contracts	Other income (expenses) net gain (loss) on derivative contracts	60,335	108,358	155,742	287,579
Total net gain (loss) on commodity contracts		$ 147,892	$ (4,533)	$ 345,970	$ 190,827
Interest rate swaps:					
Unrealized loss on interest rate swaps	Other income (expenses) net gain (loss) on derivative contracts	$	$ (2,280)	$	$
Realized gain on interest rate swaps	Other income (expenses) net gain (loss) on derivative contracts		5,245		5,533
Total net gain on interest rate swaps		$	$ 2,965	$	$ 5,533
Total net gain (loss) on derivative contracts	Other income (expenses) net gain (loss) on derivative contracts	$ 147,892	$ (1,568)	$ 345,970	$ 196,360

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At September 30, 2010, the Company had the following open derivative contracts:

				September 30, 2010			
				Floors		Ceilings	
Period	Instrument	Commodity	Volume in Mmbtu s/ Bbl s/Gal s	Price / Price Range	Weighted Average Price	Price / Price Range	Weighted Average Price
October 2010-December 2010	Collars	Natural gas	34,960,000	$5.00 - $7.00	$5.97	$9.00 - $10.00	$9.21
October 2010-December 2010	Swaps	Natural gas	460,000	8.22	8.22		
October 2010-December 2010	Put Options	Natural gas	9,200,000	5.00	5.00		
October 2010-December 2010	Collars	Crude Oil	184,000	80.00	80.00	96.75 - 97.00	96.88
October 2010-December 2010	Swaps	Crude Oil	69,000	75.15 - 75.55	75.28		
October 2010-December 2010	Swaps	Natural gas liquids	3,600,000	0.47 - 0.48	0.47		
January 2011-December 2011	Collars	Natural gas	189,800,000	5.50 - 6.00	5.55	9.00 - 10.30	9.66
January 2011-December 2011	Collars	Crude Oil	1,825,000	75.00 - 80.00	78.00	95.00 - 101.00	99.27
January 2011-December 2011	Swaps	Natural gas liquids	4,800,000	0.46	0.46		
January 2012-December 2012	Collars	Natural gas	78,690,000	5.00	5.00	7.50 - 8.00	7.55
January 2012-December 2012	Collars	Crude Oil	3,660,000	75.00 - 80.00	77.00	98.00 - 102.45	100.00

At December 31, 2009, the Company had the following open derivative contracts:

				December 31, 2009			
				Floors		Ceilings	
Period	Instrument	Commodity	Volume in Mmbtu s/ Bbl s	Price / Price Range	Weighted Average Price	Price / Price Range	Weighted Average Price
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	Put Options	Natural gas	25,640,000	4.49 - 5.00	4.87		
January 2010-December 2010	Swaps	Crude Oil	273,750	75.15 - 75.55	75.28		
January 2011-December 2011	Collars	Natural gas	142,350,000	5.50 - 6.00	5.56	9.00 - 10.30	9.88

9. STOCKHOLDERS EQUITY

On August 11, 2009, the Company sold an aggregate of 25.0 million shares of its common stock in an underwritten public offering. The gross proceeds from the sale were approximately $572 million, before deducting underwriting discounts and commissions and expenses of $22 million.

On March 4, 2009, the Company sold an aggregate of 22.0 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 expenses of $9 million.

Warrants, Options and Stock Appreciation Rights

During the nine months ended September 30, 2010, the Company granted stock options covering 2.1 million shares of common stock to employees of the Company. The stock options have exercise prices ranging from $15.47 to $23.58 with a weighted average price of $21.10. 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 September 30, 2010, the unrecognized compensation expense related to non-vested stock appreciation rights and stock options totaled $17.2 million and will be recognized on a straight-line basis over the weighted average remaining vesting period of 1.2 years.

During the nine months ended September 30, 2009, the Company granted stock options covering 1.6 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 $15.47. 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.

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During the nine months ended September 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 the PHAWK, LLC transaction in the second quarter of 2004.

Restricted Stock

During the nine months ended September 30, 2010, the Company granted 1.2 million shares of restricted stock to employees of the Company and non-employee directors. These restricted shares were granted at prices ranging from $15.47 to $23.58 with a weighted average price of $20.84. 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 September 30, 2010, the unrecognized compensation expense related to non-vested restricted stock totaled $19.2 million and was to be recognized on a straight-line basis over the weighted average remaining vesting period of 1.1 years.

During the nine months ended September 30, 2009, the Company granted 0.7 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 $15.81. 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.

Assumptions

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

	Nine Months Ended September 30, 2010	2009
Weighted average value per option granted during the period	$ 10.26	$ 7.23
Assumptions [(1)]:		
Stock price volatility	62.0%	70.0%
Risk free rate of return	2.02%	1.49%
Expected term	4.0 years	3.0 years

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

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10. EARNINGS PER SHARE

The following represents the calculation of earnings per share:

	Three Months Ended September 30, 2010	Three Months Ended September 30, 2009	Nine Months Ended September 30, 2010	Nine Months Ended September 30, 2009
	(In thousands, except per share amounts)			
Basic				
Net income (loss)	$ 98,681	$ (40,177)	$ 268,311	$ (1,061,934)
Weighted average basic number of shares outstanding	300,543	287,913	300,377	273,477
Basic net income (loss) per share	$ 0.33	$ (0.14)	$ 0.89	$ (3.88)
Diluted				
Net income (loss)	$ 98,681	$ (40,177)	$ 268,311	$ (1,061,934)
Weighted average basic number of shares outstanding	300,543	287,913	300,377	273,477
Common stock equivalent shares representing shares issuable upon exercise of stock options and stock appreciation rights	299	Anti-dilutive	1,063	Anti-dilutive
Common stock equivalent shares representing shares issuable upon exercise of warrants				Anti-dilutive
Common stock equivalent shares representing shares included upon vesting of restricted shares	1,099	Anti-dilutive	1,101	Anti-dilutive
Weighted average diluted number of shares outstanding	301,941	287,913	302,541	273,477
Diluted net income (loss) per share	$ 0.33	$ (0.14)	$ 0.89	$ (3.88)

Common stock equivalents, including stock options, stock appreciation rights (SARS) and warrants, totaling 3.1 million and 2.2 million shares were not included in the computations of diluted earnings per share for the three and nine months ended September 30, 2010, respectively, as the effect would have been anti-dilutive because the grant prices were greater than the average market price of the common shares. Common stock equivalents, including stock options, SARS and warrants, totaling 4.8 million and 4.6 million shares were not included in the computation of diluted earnings per share as the effect would have been anti-dilutive for the three and nine months ended September 30, 2009, respectively, due to the net losses.

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11. ADDITIONAL FINANCIAL STATEMENT INFORMATION

Certain balance sheet amounts are comprised of the following:

	September 30, 2010	December 31, 2009
	(In thousands)	
Accounts receivable:		
Oil and natural gas revenues	$ 119,156	$ 100,294
Marketing revenues	35,111	38,180
Joint interest accounts	121,810	75,316
Income and other taxes receivable	22,738	22,743
Other	5,979	2,731
	$ 304,794	$ 239,264
Prepaids and other:		
Prepaid insurance	$ 5,169	$ 2,478
Prepaid drilling costs	53,037	27,617
Other	2,632	2,339
	$ 60,838	$ 32,434
Accounts payable and accrued liabilities:		
Trade payables	$ 42,805	$ 75,549
Revenues and royalties payable	173,363	155,568
Accrued oil and natural gas capital costs	325,302	175,369
Accrued midstream capital costs	15,419	29,570
Accrued interest expense	48,895	69,410
Prepayment liabilities	25,184	36,714
Accrued lease operating expenses	10,746	11,407
Accrued ad valorem taxes payable	13,408	5,151
Accrued employee compensation	19,413	11,820
Income taxes payable	11,140	533
Other	76,925	62,080
	$ 762,600	$ 633,171

12. SEGMENTS

In accordance with ASC 280, *Segment Reporting*, the Company has identified two reportable segments: oil and natural gas production and midstream operations. The oil and natural gas production segment is responsible for acquisition, exploration, development and production of oil and natural gas properties, while the midstream operations segment is responsible for gathering and treating natural gas for the Company and third parties. The Company s Chief Operating Decision Maker evaluates the performance of the reportable segments based on *Income (loss) before income taxes* .

In the beginning of the fourth quarter of 2009, the Company made a strategic decision to focus on and allocate resources to its midstream operations division. The decision to designate the midstream operations division as a separate business segment was due primarily to the growth and success within the division as a result of the significant investment of capital during 2009, as well as the Company s intention to increase third party throughput. As discussed in Note 2, *Acquisitions and Divestitures* and Note 13 *Equity Method Investment* , on May 21, 2010, the Company contributed its Haynesville Shale gathering and treating business to form a new joint venture entity with Kinder Morgan. The Company accounts for its 50% investment in the new entity, KinderHawk Field Services LLC, under the equity method and the revenues and expenses associated with the Haynesville Shale gathering and treating business are no longer presented within the Company s consolidated revenues and expenses in the unaudited condensed consolidated income statements. Although the Haynesville Shale gathering and treating business represents a significant portion of the Company s midstream operations segment revenues and expenses, the Company s midstream operations segment continues to operate in the

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Fayetteville and Eagle Ford Shales. The Company pays to KinderHawk negotiated gathering and treating fees, which are included in *Gathering, transportation and other* on the unaudited condensed consolidated income statements, and are discussed further in Note 2, *Acquisitions and Divestitures.*

The Company s oil and natural gas segment and midstream segment revenues and expenses include intersegment transactions, which are generally based on transactions made at market-related rates. Consolidated revenues and expenses reflect the elimination of all intercompany transactions. The accounting policies of the reporting segments are the same as those described in the *Summary of Significant Events and Accounting Policies* in Note 1 of the 2009 Annual Report on Form 10-K.

Summarized financial information concerning our reportable segments is shown in the following table (in thousands):

	Oil and Natural Gas	Midstream	Intersegment Eliminations	Consolidated Total
For the three months ended September 30, 2010:				
Revenues	$ 403,309	$ 5,873	$	$ 409,182
Intersegment revenues		3,524	(3,524)	
Total revenues	$ 403,309	$ 9,397	$ (3,524)	$ 409,182
Gathering, transportation and other	(50,165)	(3,405)	3,524	(50,046)
Depletion, depreciation and amortization	(105,800)	(2,012)		(107,812)
General and administrative	(36,022)	(4,403)		(40,425)
Interest expense and other	(118,858)	8,144		(110,714)
Amortization of deferred gain		59,472		59,472
Equity investment income		8,572		8,572
Income before income taxes	$ 85,908	$ 75,793	$	$ 161,701
Total assets	$ 6,912,153	$ 819,197	$ (29,855)	$ 7,701,495
Capital expenditures	$ (535,301)	$ (28,415)	$	$ (563,716)
For the three months ended September 30, 2009:				
Revenues	$ 229,838	$ 8,100	$	$ 237,938
Intersegment revenues		15,954	(15,954)	
Total revenues	$ 229,838	$ 24,054	$ (15,954)	$ 237,938
Gathering, transportation and other	(33,626)	(5,071)	15,954	(22,743)
Depletion, depreciation and amortization	(88,438)	(3,254)		(91,692)
General and administrative	(22,365)	(2,185)		(24,550)
Interest expense and other	(52,107)	(6,874)		(58,981)
(Loss) income before income taxes	$ (71,527)	$ 6,488	$	$ (65,039)
Total assets	$ 5,965,971	$ 478,647	$ (37,150)	$ 6,407,468
Capital expenditures	$ (417,629)	$ (78,632)	$	$ (496,261)

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	Oil and Natural Gas	Midstream	Intersegment Eliminations	Consolidated Total
For the nine months ended September 30, 2010:				
Revenues	$ 1,181,191	$ 21,810	$	$ 1,203,001
Intersegment revenues		42,662	(42,662)	
Total revenues	$ 1,181,191	$ 64,472	$ (42,662)	$ 1,203,001
Gathering, transportation and other	(141,881)	(15,077)	42,662	(114,296)
Depletion, depreciation and amortization	(307,107)	(7,954)		(315,061)
General and administrative	(98,931)	(17,043)		(115,974)
Interest expense and other	(234,028)	(1,065)		(235,093)
Amortization of deferred gain		123,839		123,839
Equity investment income		10,619		10,619
Income before income taxes	$ 282,366	$ 156,526	$	$ 438,892
Total assets	$ 6,912,153	$ 819,197	$ (29,855)	$ 7,701,495
Capital expenditures	$ (1,752,624)	$ (191,220)	$	$ (1,943,844)
For the nine months ended September 30, 2009:				
Revenues	$ 708,379	$ 20,314	$	$ 728,693
Intersegment revenues		33,410	(33,410)	
Total revenues	$ 708,379	$ 53,724	$ (33,410)	$ 728,693
Gathering, transportation and other	(85,811)	(13,469)	33,410	(65,870)
Depletion, depreciation and amortization	(282,187)	(8,196)		(290,383)
General and administrative	(63,467)	(4,714)		(68,181)
Full cost ceiling impairment	(1,732,486)			(1,732,486)
Interest expense and other	(155,992)	(14,937)		(170,929)
(Loss) income before income taxes	$ (1,723,940)	$ 11,805	$	$ (1,712,135)
Total assets	$ 5,965,971	$ 478,647	$ (37,150)	$ 6,407,468
Capital expenditures	$ (1,168,023)	$ (221,691)	$	$ (1,389,714)

13. EQUITY METHOD INVESTMENT

The Company s investment in an unconsolidated entity in which the Company does not have a majority interest, but does have significant influence, is accounted for under the equity method. Under the equity method of accounting, the Company s share of net income (loss) from its equity affiliate is reflected as an increase (decrease) in its investment account in *Other noncurrent assets* and is also recorded as equity investment income (loss) in *Other income (expenses).* Distributions from the equity affiliate are recorded as reductions of the Company s investment and contributions to the equity affiliate are recorded as increases of the Company s investment.

The Company reviews its equity method investment for potential impairment whenever events or changes in circumstances indicate that an other-than-temporary decline in the value of the investment has occurred.

Investment in KinderHawk Field Services LLC

As discussed in Note 2, *Acquisitions and Divestitures,* on May 21, 2010, the Company and Kinder Morgan formed a new joint venture entity, KinderHawk Field Services LLC, which engages in the natural gas midstream business in Northwest Louisiana, focused on the Haynesville Shale formation. As part of the transaction, the Company contributed its Haynesville Shale gathering and treating business in Northwest Louisiana to KinderHawk and Kinder Morgan contributed approximately $921 million in cash, to the new entity. The cash was distributed by KinderHawk to the Company and each of the Company and Kinder Morgan owns a 50% membership interest in KinderHawk. The Company accounts for its 50% membership interest in KinderHawk as an equity method investment. As of September 30, 2010, the Company s investment in KinderHawk totaled $206.5 million.

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At May 21, 2010, as of a result of the transaction, the Company recorded a deferred gain of approximately $713.8 million for the difference between 50% of the net carrying value of the assets the Company contributed to the joint venture and the net cash proceeds from KinderHawk, representing the cash contributed by Kinder Morgan at closing for its 50% membership interest in KinderHawk. The Company will recognize the portion of the deferred gain equal to its capital commitment over the remainder of 2010 and 2011 as contributions to KinderHawk are made or upon expiration. In addition to the capital commitment, the Company guaranteed to deliver certain minimum volumes of natural gas through the Haynesville gathering system for the next five years, as discussed in Note 2, *Acquisitions and Divestitures*. The Company will recognize the remaining deferred gain as volumes are delivered through the Haynesville gathering system over the next five years. As of September 30, 2010, the balance of the Company s deferred gain was $595.5 million.

The summarized unaudited income statement information for KinderHawk from May 21, 2010 (date of formation) through September 30, 2010 is as follows (in thousands):

Operating revenues	$ 39,317
Operating expenses	(21,589)
Operating income	17,728
Interest expense and other	(380)
Income tax expense	
Net income	$ 17,348

14. SUBSEQUENT EVENT

The Company is currently undergoing a redetermination of the borrowing base under its Senior Credit Agreement. The Company expects to finalize the redetermination during the fourth quarter of 2010. The redetermination of the portion of the borrowing base which relates to the Company s oil and natural gas properties can be impacted by changes in the Company s oil and natural gas properties, reserves, other indebtedness and other relevant factors. The component of the borrowing base related to the Company s midstream assets is limited to the lesser of $100 million or 3.5 times midstream EBITDA and is calculated quarterly.

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

The following discussion is intended to assist in understanding our results of operations and our current financial position for the three and nine months ended September 30, 2010 and 2009 and should be read in conjunction with our unaudited condensed consolidated financial statements and the notes thereto included in this Quarterly Report on 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 for the year ended December 31, 2009. Statements in this discussion may be forward-looking. These forward-looking statements involve risks and uncertainties, including those discussed below, which could cause actual results to differ from those expressed.

Overview

We are an independent oil and natural gas company engaged in the exploration, development and production of predominately natural gas properties located onshore in the United States. Our business is comprised of an oil and natural gas production segment and a midstream operations segment. Our oil and natural gas properties are concentrated in four premier domestic shale plays that we believe have decades of future development potential. We organize our oil and natural gas production operations into two principal regions: the Mid-Continent, which includes our Louisiana, Arkansas and East Texas properties; and the Western, which includes our South Texas properties. Our midstream operations segment consists of our gathering subsidiary, Hawk Field Services, LLC (Hawk Field Services or HFS) which was formed to integrate our active drilling program with activities of third parties and to develop additional gathering and treating capacity serving the Haynesville Shale and Bossier Shale in North Louisiana, the Fayetteville Shale in Arkansas and the Eagle Ford Shale in South Texas. On May 21, 2010, Hawk Field Services contributed our Haynesville Shale gathering and treating business to a new joint venture entity, KinderHawk Field Services LLC in exchange for a 50% membership interest and approximately $921 million in cash. See further discussion of the new joint venture below.

Historically, we have grown through acquisitions of proved oil and natural gas 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. 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. 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 are expected to be an important factor determining our capital expenditures focus over the next nine to twelve months.

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.

Our average daily oil and natural gas production increased 38% in the first nine months of 2010, during which we averaged 645 million cubic feet of natural gas equivalent (Mmcfe) per day (Mmcfe/d) compared to average daily production of 469 Mmcfe/d during the first nine months of 2009. The increase in production compared to the prior year period is driven by our drilling successes in the Haynesville, Fayetteville and Eagle Ford Shales as our production gains have made up for our sold production associated with our 2010 asset sales, as discussed below. Overall, we drilled or participated in the drilling of 684 gross wells (160.5 net wells) of which 682 gross (159.8 net) were successful, resulting in a success rate of 99%.

During the third quarter of 2010, we issued $825 million aggregate principal of our 7.25% Senior Notes due 2018 (the 2018 Notes). The proceeds from the 2018 Notes were utilized to repurchase our $775 million 9.125% Senior Notes due 2013 (the 2013 Notes), which allowed us to reduce our future interest expense as a result of the lower interest rate and to extend the maturity of these bonds. Due to the early repurchase of the 2013 Notes, we incurred charges of approximately $47.1 million in the third quarter of 2010. These charges are recorded in *Interest expense and other* on the unaudited condensed consolidated statements of operations and include the cash premium paid to noteholders for the early repurchase of the 2013 Notes, as well as non-cash charges related to the write-off of debt issuance costs, discounts and premiums associated with the 2013 Notes.

Our 2010 capital budget is focused on the development of non-proved reserve locations in our Haynesville, Bossier, Eagle Ford and Fayetteville Shale plays so that we can hold our acreage in these areas. We also believe these projects offer us the potential for high internal rates of return and reserve growth. We are adjusting our 2010 capital budget to $2.55 billion, which includes capital spending for drilling and completions, midstream operations and acquisitions. This increase is largely driven by service cost inflation, specifically pressure pumping services both in the Haynesville Shale and the Eagle Ford Shale, and a much larger amount of non-operated drilling than was estimated in early 2010. We expect that 2010 and 2011 capital spending will be funded through a combination of internally generated cash flow, prior and future non-core asset sales and availability under our Senior Credit Agreement.

Capital spending for 2011 is estimated at $2.3 billion, of which $1.9 billion will be allocated for drilling and completions, $200 million will be allocated for midstream operations and $200 million will be allocated for potential acquisitions. Of the $1.9 billion budget for drilling and completions, approximately $900 million is planned for the Haynesville Shale, approximately $900 million is budgeted for the Eagle Ford Shale, and approximately $100 million is budgeted for the Fayetteville Shale. This spending contemplates an increase in drilling activity in the Eagle Ford Shale throughout the year and a significant decrease in the Haynesville Shale operated rig count in the second half of the year, down to approximately seven rigs. Our emphasis in 2011 will be development of condensate-rich properties with a shift away from dry gas development. The $1.9 billion dollar drilling and completion budget for 2011 emphasizes capital spending based on market conditions, opportunities to accelerate certain areas of our Eagle Ford Shale position, and the desire to reduce capital allocated to pure natural gas drilling once the Haynesville Shale lease capture period is effectively completed in mid-year 2011. Capital allocated to the Eagle Ford Shale is approximately two and a half times the amount budgeted in 2010. Capital allocated to the Haynesville Shale is expected to decrease by 35% from 2010 levels.

Our goal in 2010 is to strengthen our balance sheet by completing asset dispositions, including a transaction involving our midstream assets, divesting our interest in the Terryville Field in Northwest Louisiana, divesting our interest in the West Edmond Hunton Lime Unit (WEHLU) in Central Oklahoma as well as divesting other non-core assets. To date, we have sold approximately $640 million in properties, including $155 million for the sale of our WEHLU Field in Oklahoma County, Oklahoma, $320 million for the sale of our Terryville Field in Lincoln and Claiborne Parishes, Louisiana, approximately $123 million for certain Mid-Continent properties in Texas, Oklahoma and Arkansas and approximately $38 million for other various non-core properties. We also formed a joint venture, on May 21, 2010, discussed in greater detail below, in which we received approximately $921 million (including approximately $46 million in closing adjustments) for a 50% interest in our Haynesville Shale gathering and treating business in North Louisiana. During the remainder of 2010 we intend to market our upstream and midstream assets in the Fayetteville Shale in Arkansas. A divestment will only occur if we receive bids that we determine are favorable.

Hawk Field Services, LLC Joint Venture

On May 21, 2010, our wholly owned subsidiary, Hawk Field Services, and KM Gathering LLC (Kinder Morgan), an affiliate of Kinder Morgan Energy Partners, L.P., a publicly traded master limited partnership, formed a new joint venture pursuant to a Formation and Contribution Agreement (Contribution Agreement). The new joint venture entity, KinderHawk Field Services LLC (KinderHawk), engages in the natural gas midstream business in Northwest Louisiana, focused on the Haynesville Shale formation. Pursuant to the Contribution Agreement, Hawk Field Services contributed to KinderHawk our Haynesville Shale gathering and treating business in Northwest Louisiana, and Kinder Morgan contributed approximately $921 million in cash ($875 million for a 50% membership interest in KinderHawk and $46 million for certain closing adjustments including 2010 capital expenditures through the closing date) to KinderHawk. We, along with Kinder Morgan, own a 50% membership interest in KinderHawk. KinderHawk distributed the approximate $921 million to us. The joint venture has an economic effective date of January 1, 2010, and HFS continued to operate the business until September 30, 2010, at which date HFS and Kinder Morgan terminated the transition services agreement and KinderHawk assumed operations of the joint venture. We account for our interest in KinderHawk under the equity method of accounting.

We are obligated to deliver minimum annual quantities of natural gas to KinderHawk equal to 50% of our annual projected production from Petrohawk operated wells located on certain dedicated acreage from the Haynesville and Bossier Shales in North Louisiana for the next five years, or in the alternative, pay an annual true-up fee to KinderHawk if such minimum annual quantities are not delivered. We pay KinderHawk negotiated gathering and treating fees, subject to an annual inflation adjustment factor. The gathering fee is equal to $0.34 per Mcf of natural gas delivered at KinderHawk s receipt points. The treating fee is charged for gas delivered containing more than 2% by volume of carbon dioxide. For gas delivered containing between 2% and 5.5% carbon dioxide, the treating fee is between $0.030 and $0.345 per Mcf, and for gas containing over 5.5% carbon dioxide, the treating fee starts at $0.365 per Mcf and increases on a scale of $0.09 per Mcf for each additional 1% of carbon dioxide content.

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, asset dispositions, and access to capital markets, to the extent available. 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 our production levels. We continue to monitor our liquidity and the capital markets. 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 future capital resources and liquidity depend, in part, on our success in developing our leasehold interests. Cash is required to fund capital expenditures necessary to offset inherent declines in our production and proven reserves, which is typical in the capital-intensive oil and natural gas industry. Future success in growing reserves and production will be highly dependent on our capital resources and our success in finding additional reserves. During 2008 and 2009, we raised $1.3 billion of debt (net of discounts and expenses) and $2.7 billion of equity capital (net of discounts and expenses) and we refinanced $775 million of debt in 2010. We expect to fund our future capital requirements through internally generated cash flows, borrowings under our Senior Credit Agreement, asset dispositions, and accessing the capital markets, if necessary. The Senior Credit Agreement provides for a $2.0 billion facility. Effective as of September 30, 2010, the borrowing base was approximately $1.1 billion, $1.0 billion of which relates to our oil and natural gas properties and $100 million of which relates to our midstream assets (currently limited as described below). The portion of the borrowing base which relates to our oil and natural gas properties 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 our oil and natural gas properties, reserves, other indebtedness and other relevant factors. The component of the borrowing base related to our midstream assets is limited to the lesser of $100 million or 3.5 times midstream EBITDA, is calculated quarterly and is currently limited to approximately $53 million based on the EBITDA limitation. We are currently undergoing a redetermination of the borrowing base under our Senior Credit Agreement and we expect to finalize the redetermination during the fourth quarter of 2010. Our ability to utilize the full amount of our borrowing capacity is influenced by a variety of factors, including semi-annual

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redeterminations of our borrowing base, which may also be redetermined periodically at the discretion of our lenders, and covenants under our Senior Credit Agreement and our senior unsecured debt indentures. Our Senior Credit Agreement contains customary 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 (as defined in the Senior Credit Agreement) of not less than 2.5 to 1.0. We are subject to additional covenants limiting dividends and other restricted payments, transactions with affiliates, incurrence of debt, changes of control, asset sales, and liens on properties. Additionally, the indentures governing our senior unsecured debt contain covenants limiting our ability to incur additional indebtedness, including borrowings under our Senior Credit Agreement, unless we meet one of two alternative tests. The first test applies to all indebtedness and requires that after giving effect to the incurrence of additional debt the ratio of our adjusted consolidated EBITDA (as defined in our indentures) to our adjusted consolidated interest expense over the trailing four fiscal quarters will be at least 2.5 to 1.0. The second test applies only to borrowings under our Senior Credit Agreement that do not meet the first test and it limits these borrowings to the greater of a fixed sum (the most restrictive indenture limit being $100 million) and a percentage (the most restrictive indenture limit being 20%) of our adjusted consolidated net tangible assets (as defined in all of our indentures), which is determined using discounted future net revenues from proved natural gas and oil reserves as of the end of each year.

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 aggressive drilling plans 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 subject to market conditions.

During the third quarter of 2010, we issued $825 million aggregate principal amount of our 7.25% Senior Notes due 2018 (the 2018 Notes). The proceeds from the 2018 Notes were utilized to repurchase our $775 million 9.125% Senior Notes due 2013 (the 2013 Notes), which allowed us to reduce our future interest expense as a result of the lower interest rate and to extend the maturity of these bonds. Due to the early repurchase of the 2013 Notes, we incurred charges of approximately $47.1 million in the third quarter of 2010. These charges are recorded in *Interest expense and other* on the unaudited condensed consolidated statements of operations and include the cash premium paid to noteholders for the early repurchase of the 2013 Notes, as well as non-cash charges related to the write-off of debt issuance costs, discounts and premiums associated with the 2013 Notes.

In conjunction with the KinderHawk joint venture discussed previously, we are obligated to commit up to an additional $105.4 million, as of September 30, 2010, in capital contributions to KinderHawk during 2010 and 2011, if KinderHawk requires capital to fund its capital expenditures. Additional contributions above this amount can be made at our discretion. Our obligation to contribute capital to KinderHawk could impact our development plans by reducing the amount of capital available to fund our drilling program. Capital contributions required to be made to KinderHawk will be factored into our overall analysis of capital resources and liquidity on an ongoing basis.

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

Cash Flow

Our primary sources of cash for the nine months ended September 30, 2010 were funds from asset sales, operating activities and debt refinancing, which were partially offset by net repayments on our Senior Credit

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Agreement and cash used in investing activities to fund our drilling program and acquisition activities. Our primary sources of cash for the nine months ended September 30, 2009 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 on 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 increase (decrease) in cash is summarized as follows:

	Nine Months Ended September 30, 2010	2009
	(In thousands)	
Cash flows provided by operating activities	$ 362,413	$ 474,750
Cash flows used in investing activities	(249,311)	(1,483,517)
Cash flows (used in) provided by financing activities	(110,461)	1,003,576
Net increase (decrease) in cash	$ 2,641	$ (5,191)

Operating Activities. Net cash provided by operating activities for the nine months ended September 30, 2010 and 2009 were $362.4 million and $474.8 million, respectively.

Net cash provided by operating activities decreased in 2010 primarily due to the decrease in realized gains on our derivative contracts from $287.6 million for the nine months ended September 30, 2009 to $155.7 million for the same period in 2010. This decrease was offset by a 38% increase in our average daily production volumes due to our drilling successes in the Haynesville, Fayetteville and Eagle Ford Shales. Our natural gas equivalent price increased $0.82 per Mcfe to $4.65 per Mcfe from $3.83 per Mcfe in the prior year. Production for the first nine months of 2010 averaged 645 Mmcfe/d compared to 469 Mmcfe/d during the same period of 2009. As a result of our 2010 and 2011 capital budget programs, we expect to continue to increase our production volumes throughout 2010 and 2011. However, we are unable to predict future production levels or future commodity prices with certainty, 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 $249.3 million and $1.5 billion for the nine months ended September 30, 2010 and 2009, respectively.

During the first nine months of 2010, we spent $1.7 billion on oil and natural gas capital expenditures. To date in 2010, we participated in the drilling of 684 gross wells (160.5 net wells). We spent an additional $212.1 million on other operating property and equipment capital expenditures, primarily to fund the development of our gathering systems in the Haynesville Shale in Northwest Louisiana and the Eagle Ford Shale in South Texas.

On September 29, 2010, we completed the sale of our interest in certain Mid-Continent properties in Texas, Oklahoma and Arkansas for approximately $123 million before customary closing adjustments. Proceeds from the sale were recorded as a reduction to the carrying value of our full cost pool with no gain or loss recorded. The transaction had an effective date of July 1, 2010.

On May 21, 2010, our wholly owned subsidiary, Hawk Field Services, and Kinder Morgan entered into a joint venture arrangement to create a new entity, KinderHawk, which engages in the natural gas midstream business in Northwest Louisiana, focused on the Haynesville Shale formation. Hawk Field Services contributed to KinderHawk our Haynesville Shale gathering and treating business in Northwest Louisiana, and Kinder Morgan contributed approximately $921 million in cash ($875 million for a 50% membership interest in KinderHawk and $46 million for certain closing adjustments including 2010 capital expenditures through the closing date) to KinderHawk. We, along with Kinder Morgan, own a 50% membership interest in KinderHawk. KinderHawk distributed the approximate $921 million to us. During the first nine months of 2010, we have made contributions of $11.0 million to KinderHawk to partially fund the 2010 capital program and have received distributions of $13.2 million, which are recorded in cash flows from operating activities.

On May 12, 2010, we completed the sale of our interest in Terryville Field, located in Lincoln and Claiborne Parishes, Louisiana for $320 million before customary closing adjustments. Proceeds from the sale were recorded as a reduction to the carrying value of our full cost pool with no gain or loss recorded. The transaction had an effective date of January 1, 2010. In conjunction with the closing, we deposited $75 million with a qualified intermediary to facilitate like-kind exchange transactions. At September 30, 2010, the Company had $42.9 million remaining for use in future acquisitions.

On April 30, 2010, we completed the sale of our interest in the WEHLU Field in Oklahoma County, Oklahoma for $155 million before customary closing adjustments. Proceeds from the sale were recorded as a reduction to the carrying value of our full cost pool with no gain or loss recorded. The transaction had an effective date of April 1, 2010. In conjunction with the closing, we assigned five natural gas swaps and five crude oil swaps to one of the purchasers.

During the first nine months of 2010, we sold our interests in various non-core properties for aggregate proceeds of approximately $38 million. Proceeds from the sales were recorded as a reduction to the carrying value of our full cost pool with no gain or loss recorded.

During the first nine months of 2010, we purchased and redeemed $1.1 billion of marketable securities. These marketable securities were classified and accounted for as trading securities and were used primarily to fund a portion of our 2010 capital program.

During the first nine months of 2010, we had a net decrease in restricted cash of $170.8 million. Restricted cash was used to fund a portion of our 2010 oil and natural gas acquisitions.

During the first nine months of 2009, we spent $1.2 billion on oil and natural gas capital expenditures. We participated in the drilling of 467 gross wells (123.3 net wells). We spent an additional $225.3 million on other 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 Northwest Louisiana and the Eagle Ford Shale in Texas.

During the first nine months of 2009, we used excess funds to purchase a net $27.0 million of marketable securities. These marketable securities were classified and accounted for as trading securities and were used primarily to fund a portion of our 2009 capital program.

On October 30, 2009, we sold our Permian Basin properties for $376 million in cash, before customary closing adjustments. In conjunction with the signing of the agreement, we received a $37.6 million deposit. Proceeds from the sale were recorded as a reduction to the carrying value of our full cost pool with no gain or loss recorded.

On July 31, 2009, we purchased all outstanding membership interests in Kaiser Trading, LLC (Kaiser) for approximately $105 million. Kaiser s only assets were transportation-related contracts including a firm

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transportation contract, interruptible gas transportation service agreement, parking and lending services agreement, and a pooling services agreement.

Financing Activities. Net cash flows used in financing activities for the nine months ended September 30, 2010 were $110.5 million and net cash flows provided by financing activities for the nine months ended September 30, 2009 were $1.0 billion.

On August 17, 2010, we completed a private placement offering to eligible purchasers of an aggregate principal amount of $825 million 7.25% senior notes due August 15, 2018. The net proceeds from the sale of the 2018 Notes were approximately $809.5 million, after deducting offering expenses. We capitalized $16.7 million of debt issuance costs in conjunction with the issuance of the 2018 Notes.

On August 16, 2010, tenders and consents had been received from holders of $652.7 million in aggregate principal amount of the 2013 Notes, representing approximately 85% of the outstanding 2013 Notes. On August 17, 2010, we accepted the 2013 Notes that had been so tendered and utilized approximately $689.5 million in net proceeds from the sale of the 2018 Notes to redeem such 2013 Notes. Approximately $116.0 million in aggregate principal amount of 2013 Notes were redeemed on September 20, 2010.

On August 11, 2009, we sold an aggregate of 25.0 million shares of our common stock in an underwritten public offering. The net proceeds from the sale were approximately $550 million, after deducting underwriting discounts and commissions and expense.

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 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 2014 (the 2014 Notes). The net proceeds from the sale of the 2014 Notes were approximately $535.4 million, after deducting the initial purchasers discounts and offering expenses and commissions.

Capital financing and excess cash flow from operations are used to repay borrowings under our Senior Credit Agreement to the extent available. During the first nine months of 2010, we had net repayments of borrowings of $90.9 million, which included repayments under our Senior Credit Agreement and the effects of our debt refinancing in the third quarter of 2010. During the first nine months of 2009, we had net borrowings of $88.2 million.

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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. The following table summarizes our contractual obligations and commitments as of September 30, 2010:

	Total Obligation Amount(1) (In thousands)	Years Remaining
Natural gas transportation commitments	$ 1,942,209	19
Drilling rig commitments	209,923	2
Non-cancelable operating leases	31,888	9
Pipeline and well equipment obligations	139,744	2
Various contractual commitments (including, among other things, rental equipment obligations and obtaining and processing seismic data)	18,632	3
Total commitments	$ 2,342,396	

(1) On May 21, 2010, we created a new joint venture with Kinder Morgan, KinderHawk, which engages in the natural gas midstream business in Northwest Louisiana, focused on the Haynesville Shale formation. As part of this transaction, we are committed to contribute up to an additional $105.4 million as of September 30, 2010 in capital during 2010 and 2011 in the event KinderHawk requires capital to finance its planned capital expenditures. This obligation is not reflected in the amounts shown in the above table. In addition, we are obligated to deliver minimum annual quantities of natural gas to KinderHawk equal to 50% of our annual projected production from Petrohawk operated wells located on certain dedicated acreage from the Haynesville and Bossier Shales in North Louisiana for the next five years, or in the alternative, pay an annual true-up fee to KinderHawk if such minimum annual quantities are not delivered. We pay to KinderHawk negotiated gathering and treating fees, subject to an annual inflation adjustment factor.

Critical Accounting Policies and Estimates

Our discussion and analysis of our financial condition and results of operations are based upon the unaudited condensed consolidated financial statements, which have been prepared in accordance with accounting principles generally accepted in the United States. Preparation of these unaudited condensed consolidated financial statements requires us to make estimates and judgments that affect the reported amounts of assets, liabilities, revenues and expenses. There have been no material changes to our critical accounting policies from those described in our Annual Report on Form 10-K for the year ended December 31, 2009, other than as discussed below.

On May 21, 2010, we created a new joint venture with Kinder Morgan, KinderHawk, which engages in the natural gas midstream business in Northwest Louisiana, focused on the Haynesville Shale formation. As part of the transaction, we contributed our Haynesville Shale gathering and treating business in Northwest Louisiana to KinderHawk and Kinder Morgan contributed approximately $921 million in cash to the new entity which was distributed to us. We account for our 50% membership interest in KinderHawk as an equity method investment. At May 21, 2010, as a result of the transaction, we recorded a deferred gain of approximately $713.8 million for the difference between 50% of the net carrying value of the assets we contributed to the joint venture and the net cash proceeds from KinderHawk, representing the cash contributed by Kinder Morgan at closing for its 50% membership interest in KinderHawk. We will recognize the portion of the deferred gain equal to our capital commitment over the remainder of 2010 and 2011 as contributions to KinderHawk are made or upon expiration. In addition to the capital commitment, we guaranteed to deliver certain minimum volumes of natural gas through the Haynesville gathering system for the next five years. We will recognize the remaining deferred gain as volumes are delivered through the Haynesville gathering system over the next five years. The recognition of the deferred gain is included in *Amortization of deferred gain* in our unaudited condensed consolidated statements of income. As of September 30, 2010, the balance of our deferred gain was $595.5 million.

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Results of Operations

Quarters Ended September 30, 2010 and 2009

We reported net income of $98.7 million for the three months ended September 30, 2010 compared to a net loss of $40.2 million for the comparable period in 2009, resulting in a net change of $138.9 million. The following table summarizes key items of comparison and their related change for the period indicated.

In thousands (except per unit and per Mcfe amounts)	Three Months Ended September 30, 2010	Three Months Ended September 30, 2009	Change
Net income (loss)	$ 98,681	$ (40,177)	$ 138,858
Operating revenues:			
Oil and natural gas	280,328	166,683	113,645
Marketing	122,981	63,155	59,826
Midstream	5,873	8,100	(2,227)
Expenses:			
Marketing	139,053	66,586	72,467
Production:			
Lease operating	15,794	20,788	(4,994)
Workover and other	2,758	865	1,893
Taxes other than income	(3,185)	15,204	(18,389)
Gathering, transportation and other:			
Oil and natural gas	46,641	17,672	28,969
Midstream	3,405	5,071	(1,666)
General and administrative:			
General and administrative	33,784	20,405	13,379
Stock-based compensation	6,641	4,145	2,496
Depletion, depreciation and amortization:			
Depletion Full cost	103,994	87,324	16,670
Depreciation Midstream	1,970	3,226	(1,256)
Depreciation Other	1,356	772	584
Accretion expense	492	370	122
Amortization of deferred gain	59,472		59,472
Net gain (loss) on derivative contracts	147,892	(1,568)	149,460
Interest expense and other	(110,714)	(58,981)	(51,733)
Equity investment income	8,572		8,572
Income tax (provision) benefit	(63,020)	24,862	(87,882)
Production:			
Natural gas Mmcf	60,128	44,376	15,752
Crude oil MBbl	290	383	(93)
Natural gas liquids MBbl	186	79	107
Natural gas equivalent Mmcfe (1)	62,984	47,148	15,836
Daily production Mmcfe (1)	685	512	173
Average price per unit (2):			
Natural gas price Mcf	$ 4.20	$ 3.13	$ 1.07
Crude oil price Bbl	72.96	64.64	8.32
Natural gas liquids price Bbl	34.97	30.98	3.99
Equivalent Mcfe (1)	4.45	3.52	0.93
Average cost per Mcfe:			
Production:			
Lease operating	0.25	0.44	(0.19)
Workover and other	0.04	0.02	0.02
Taxes other than income	(0.05)	0.32	(0.37)
Gathering, transportation and other:			
Oil and natural gas	0.74	0.37	0.37

Midstream	0.05	0.11	(0.06)
General and administrative:			
General and administrative	0.54	0.43	0.11
Stock-based compensation	0.11	0.09	0.02
Depletion	1.65	1.85	(0.20)

(1) Oil and natural gas liquids are converted to equivalent gas production using a 6:1 equivalent ratio. This ratio does not assume price equivalency and given price differentials, the price for a barrel of oil equivalent for natural gas may differ significantly from the price for a barrel of oil.
(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 September 30, 2010, oil and natural gas revenues increased $113.6 million from the same period in 2009, to $280.3 million. The increase was primarily due to the increase in our production of 15,836 Mmcfe, or 34% over the three months ended September 30, 2009, primarily due to our drilling successes in resource-style plays in Louisiana, Arkansas and Texas. Increased production contributed to approximately $55.7 million in revenues for the three months ended September 30, 2010. Also contributing to this increase was an increase of $0.93 per Mcfe in our realized average price to $4.45 per Mcfe from $3.52 per Mcfe in the prior year period. The increase per Mcfe led to an increase in oil and natural gas revenues of $57.9 million.

We had marketing revenues of $123.0 million and marketing expenses of $139.1 million for the three months ended September 30, 2010, resulting in a net loss of $16.1 million as compared to a net loss of $3.4 million for the same period in 2009. A subsidiary of ours purchases and sells third party natural gas produced from wells which we and third parties 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. Our net loss for the three months ended September 30, 2010 is primarily attributable to decreased margins, the amortization of our acquired transportation contracts and payments for unused pipeline capacity.

We had gross revenues from our midstream segment of $9.4 million for the three months ended September 30, 2010 compared to the same period in 2009 of $24.1 million, a decrease of $14.7 million. Gross revenues of $9.4 million included $3.5 million of inter-segment revenues that were eliminated in consolidation. On a net basis, we had revenues of $5.9 million for the three months ended September 30, 2010, a decrease of $2.2 million from the prior year. Gathering and treating throughput decreased 48.5 Bcf to 15.7 Bcf for the three months ended September 30, 2010 compared to 64.2 Bcf for the three months ended September 30, 2009, which includes 27.7 Bcf of Haynesville treating throughput. The decrease in revenues and throughput was primarily due to the contribution of the gas gathering systems and treating facilities in the Haynesville Shale to KinderHawk, offset by additional other revenues that we earned from charging a monthly management fee to KinderHawk.

Lease operating expenses decreased $5.0 million for the three months ended September 30, 2010 primarily due to our continued cost control efforts as well as the sale of our higher cost properties in 2009 and 2010. On a per unit basis, lease operating expenses decreased $0.19 per Mcfe to $0.25 per Mcfe in 2010 from $0.44 per Mcfe in 2009. The decrease on a per unit basis is primarily due to the increase in production during 2010 from our resource-style plays which typically have a lower per unit operating cost. Additionally, the sale of our Permian Basin properties in the fourth quarter of 2009, as well as the sale of our Terryville and WEHLU properties in the second quarter of 2010, contributed to a decrease in costs for the three months ended September 30, 2010 over the same period in 2009 as these properties historically operated with higher operating costs per unit.

Taxes other than income decreased $18.4 million for the three months ended September 30, 2010 as compared to the same period in 2009. 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. The credit of $3.2 million for the three months ended September 30, 2010 is primarily due to severance tax refunds related to drilling incentives for horizontal wells in the Haynesville Shale and, to a lesser extent, in Texas and Oklahoma. For the three months ended September 30, 2010, we recorded severance tax refunds totalling $14.0 million. On a per unit basis, excluding the severance tax refunds, taxes other than income decreased $0.15 per Mcfe to $0.17 per Mcfe compared to $0.32 per Mcfe in 2009. This adjusted decrease from prior year is due to severance tax exemptions related to the drilling incentives as well as a reduction in the Louisiana statutory severance tax rate.

Gathering, transportation and other expense attributable to our oil and natural gas production segment increased $29.0 million, for the three months ended September 30, 2010 as compared to the same period in 2009.

The increase was primarily due to the closing of our KinderHawk joint venture with Kinder Morgan on May 21, 2010, as gathering and treating fees now paid to KinderHawk historically had been paid to Hawk Field Services and eliminated in consolidation. We pay $0.34 per Mcf of gas that is delivered at KinderHawk s receipt points for gathering and a treating fee that ranges between $0.030 per Mcf and $0.365 per Mcf or more depending on carbon dioxide content. On a per unit basis, gathering, transportation and other expenses increased $0.37 per Mcfe to $0.74 per Mcfe in 2010 compared to $0.37 per Mcfe in 2009. The increase on a per unit basis is primarily attributable to the gathering and treating fees we are paying to KinderHawk which historically had been paid to Hawk Field Services and eliminated in consolidation.

Gathering, transportation and other expenses attributable to our midstream segment decreased $1.7 million for the three months ended September 30, 2010 compared to the same period in 2009. The decrease was primarily due to the contribution of the gas gathering systems and treating facilities in the Haynesville Shale to KinderHawk, partially offset by the current year expansion of our Eagle Ford gas gathering and treating system.

General and administrative expense for the three months ended September 30, 2010 increased $13.4 million as compared to the same period in 2009. The increase is primarily attributable to a $7.8 million increase in professional fees, including increases for legal fees and settlements, as well as for our implementation of new software systems. The remaining of $5.6 million was primarily due to an increase in payroll and employee costs, including salaries, benefits and incentives associated with the building of our work force as a result of the continued growth in our Company.

Depletion for oil and natural gas properties is calculated using the unit of production method, which depletes the capitalized costs associated with 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 $16.7 million for the three months ended September 30, 2010 from the same period in 2009, to $104.0 million. On a per unit basis, depletion expense decreased $0.20 per Mcfe to $1.65 per Mcfe. The decrease on a per unit basis is primarily due to the ceiling test impairment write-down of $106 million we recorded at December 31, 2009 as well as our property sales in 2009 and 2010.

Depreciation expense associated with our gas gathering systems decreased $1.3 million to $2.0 million for the three months ended September 30, 2010. The decrease was primarily due to the contribution of the gas gathering systems and treating facilities in the Haynesville Shale to KinderHawk and resulted in a $404 million decrease in gas gathering system and equipment assets, partially offset by the current year expansion of our Eagle Ford gas gathering and treating system. We depreciate our gas gathering systems over a 30 year useful life and begin depreciating on the estimated placed in service date.

On May 21, 2010, we contributed our Haynesville Shale gathering and treating business in exchange for a 50% membership interest in a new joint venture entity, KinderHawk, and approximately $921 million in cash. At May 21, 2010, as a result of this transaction, we recorded a deferred gain of approximately $713.8 million for the difference between 50% of the net carrying value of the assets we contributed to the joint venture and the net cash proceeds from KinderHawk, representing the cash contributed by Kinder Morgan at closing for its 50% membership interest in KinderHawk. We will recognize the portion of the deferred gain equal to our capital commitment over the remainder of 2010 and 2011 as contributions to KinderHawk are made or upon expiration. In addition to the capital commitment, we guaranteed to deliver certain minimum volumes of natural gas through the Haynesville Shale gathering system for the next five years. We will recognize the remaining deferred gain as volumes are delivered through the Haynesville Shale gathering system over the next five years. During the three months ended September 30, 2010, the Company recognized $59.5 million of the deferred gain.

We enter into derivative commodity instruments to economically hedge our exposure to price fluctuations on our anticipated oil and natural gas production. Historically, we have also entered into interest rate swaps to mitigate exposure to market rate fluctuations by converting variable interest rates (such as those on our Senior Credit Agreement) to fixed interest rates. 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

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mark-to-market value of these derivative contracts in the unaudited condensed consolidated statement of operations. At September 30, 2010, we had a $370.5 million derivative asset, $275.9 million of which was classified as current, and a $2.5 million derivative liability, $0.7 million of which was classified as current. We recorded a net derivative gain of $147.9 million ($87.6 million net unrealized gain and $60.3 million net gain for cash received on settled contracts) for the three months ended September 30, 2010 compared to a net derivative loss of $1.6 million ($115.2 million net unrealized loss and a $113.6 million net gain for cash received on settled contracts) in the same period in 2009.

Interest expense and other increased $51.7 million for the three months ended September 30, 2010 compared to the same period in 2009. Due to the early repurchase of the 2013 Notes, we incurred charges of approximately $47.1 million in the third quarter of 2010 as discussed above. Also contributing to the increase was the increased utilization of our Senior Credit Agreement and a decrease in capitalized interest.

Our investment in KinderHawk in which we do not have a majority interest, but do have significant influence, is accounted for under the equity method. Under the equity method of accounting, our share of net income (loss) from KinderHawk is reflected as an increase (decrease) in our investment account and is also recorded as equity investment income (loss). Distributions from KinderHawk are recorded as reductions of our investment and contributions to KinderHawk are recorded as increases of our investment. Our net share of KinderHawk s earnings or losses is reported as *Equity investment income* in the unaudited condensed consolidated statements of operations. For the three months ended September 30, 2010, our net share of KinderHawk s income was $8.6 million.

We had an income tax provision of $63.0 million for the three months ended September 30, 2010 due to our pre-tax income of $161.7 million compared to an income tax benefit of $24.9 million due to our pre-tax loss of $65.0 million in the prior year. The effective tax rate for the three months ended September 30, 2010 was 38.9% compared to 38.2% for the three months ended September 30, 2009. The change in the effective tax rate is primarily due to the increase in our state tax rate generated by a shift in the composition of assets among various states.

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Nine Months Ended September 30, 2010 and 2009

We reported net income of $268.3 million for the nine months ended September 30, 2010 compared to a net loss of $1.1 billion for the comparable period in 2009, resulting in a net change of $1.3 billion. The following table summarizes key items of comparison and their related change for the period indicated.

	Nine Months Ended September 30,		
In thousands (except per unit and per Mcfe amounts)	**2010**	**2009**	**Change**
Net income (loss)	$ 268,311	$ (1,061,934)	$ 1,330,245
Operating revenues:			
Oil and natural gas	820,753	492,214	328,539
Marketing	360,438	216,165	144,273
Midstream	21,810	20,314	1,496
Expenses:			
Marketing	392,984	211,722	181,262
Production:			
Lease operating	49,573	55,903	(6,330)
Workover and other	6,707	1,793	4,914
Taxes other than income	14,849	39,921	(25,072)
Gathering, transportation and other:			
Oil and natural gas	99,219	52,401	46,818
Midstream	15,077	13,469	1,608
General and administrative:			
General and administrative	98,936	57,419	41,517
Stock-based compensation	17,038	10,762	6,276
Depletion, depreciation and amortization:			
Depletion Full cost	302,389	279,072	23,317
Depreciation Midstream	7,818	8,145	(327)
Depreciation Other	3,326	2,096	1,230
Accretion expense	1,528	1,070	458
Full cost ceiling impairment		1,732,486	(1,732,486)
Amortization of deferred gain	123,839		123,839
Net gain on derivative contracts	345,970	196,360	149,610
Interest expense and other	(235,093)	(170,929)	(64,164)
Equity investment income	10,619		10,619
Income tax (provision) benefit	(170,581)	650,201	(820,782)
Production:			
Natural gas Mmcf	169,397	119,376	50,021
Crude oil MBbl	756	1,204	(448)
Natural gas liquids MBbl	373	258	115
Natural gas equivalent Mmcfe (1)	176,171	128,150	48,021
Daily production Mmcfe (1)	645	469	176
Average price per unit (2):			
Natural gas price Mcf	$ 4.43	$ 3.53	$ 0.90
Crude oil price Bbl	74.17	51.82	22.35
Natural gas liquids price Bbl	35.66	27.04	8.62
Equivalent Mcfe (1)	4.65	3.83	0.82
Average cost per Mcfe:			
Production:			
Lease operating	0.28	0.44	(0.16)
Workover and other	0.04	0.01	0.03
Taxes other than income	0.08	0.31	(0.23)
Gathering, transportation and other:			
Oil and natural gas	0.56	0.41	0.15
Midstream	0.09	0.10	(0.01)
General and administrative:			

General and administrative	0.56	0.45	0.11
Stock-based compensation	0.10	0.08	0.02
Depletion	1.72	2.18	(0.46)

(1) Oil and natural gas liquids are converted to equivalent gas production using a 6:1 equivalent ratio. This ratio does not assume price equivalency and given price differentials, the price for a barrel of oil equivalent for natural gas may differ significantly from the price for a barrel of oil.

(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 nine months ended September 30, 2010, oil and natural gas revenues increased $328.5 million from the same period in 2009, to $820.8 million. The increase was primarily due to the increase in production of 48,021 Mmcfe, or 37% over the nine months ended September 30, 2009, primarily due to our drilling successes in resource-style plays in Louisiana, Arkansas and Texas. Increased production contributed approximately $183.9 million in revenues for the nine months ended September 30, 2010. Also contributing to this increase was an increase of $0.82 per Mcfe in our realized average price to $4.65 per Mcfe from $3.83 per Mcfe in the prior year. The increase per Mcfe led to an increase in oil and natural gas revenues of $144.6 million.

We had marketing revenues of $360.4 million and marketing expenses of $393.0 million for the nine months ended September 30, 2010, resulting in a net loss of $32.6 million as compared to a net gain of $4.4 million for the same period in 2009. A subsidiary of ours purchases and sells third party natural gas produced from wells which we and third parties 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. Our net loss for the nine months ended September 30, 2010 is primarily attributable to decreased margins, amortization of our acquired transportation contracts and payments for unused pipeline capacity.

We had gross revenues from our midstream segment of $64.5 million for the nine months ended September 30, 2010 compared to the same period in 2009 of $53.7 million, an increase of $10.8 million, of which $9.3 million represents inter-segment revenues that are eliminated in consolidation. The remaining $1.5 million increase represents gathering and treating revenues from third party owners in our operated wells and revenues associated with third party producers. The increase in revenues of $1.5 million is primarily due to the receipt for a monthly management fee charged to KinderHawk as well as an increase in throughput on our Haynesville and Eagle Ford gas gathering systems partially offset by a decrease in throughput from our Fayetteville gas gathering system.

Lease operating expenses decreased $6.3 million for the nine months ended September 30, 2010 primarily due to our continued cost control efforts as well as the sale of our higher cost properties in 2009 and 2010. On a per unit basis, lease operating expenses decreased $0.16 per Mcfe to $0.28 per Mcfe in 2010 from $0.44 per Mcfe in 2009. The decrease on a per unit basis is primarily due to the increase in production during 2010 from our resource-style plays which typically have a lower per unit operating cost. Additionally, the sale of our Permian Basin properties in the fourth quarter of 2009, as well as the sale of our Terryville and WEHLU properties in the second quarter of 2010, contributed to a decrease in costs for the nine months ended September 30, 2010 over the same period in 2009 as these properties have historically operated with higher operating costs per unit.

Taxes other than income decreased $25.1 million for the nine months ended September 30, 2010 as compared to the same period in 2009. 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. Taxes other than income decreased to $14.8 million in the nine months ended September 30, 2010, primarily due to severance tax refunds related to drilling incentives for horizontal wells in the Haynesville Shale and, to a lesser extent, in Texas and Oklahoma. For the nine months ended September 30, 2010, we recorded severance tax refunds in the amount of $31.7 million. On a per unit basis, excluding the severance tax refunds, taxes other than income decreased $0.05 per Mcfe to $0.26 per Mcfe compared to $0.31 per Mcfe in 2009. This adjusted decrease from prior year is due to severance tax exemptions as well as a reduction in the Louisiana statutory severance tax rate.

Gathering, transportation and other expense attributable to our oil and natural gas production segment increased $46.8 million, for the nine months ended September 30, 2010 as compared to the same period in 2009. The increase was primarily due to the closing of our KinderHawk joint venture with Kinder Morgan on May 21, 2010, as gathering and treating fees now paid to KinderHawk historically had been paid to Hawk Field Services and eliminated in consolidation. We pay $0.34 per Mcf of gas that is delivered at KinderHawk s receipt points for gathering and a treating fee that ranges between $0.030 per Mcf and $0.365 per Mcf or more depending on carbon dioxide content. On a per unit basis, gathering, transportation and other expenses increased $0.15 per Mcfe primarily due to the gathering and treating fees we are paying to KinderHawk which historically had been paid to Hawk Field Services and eliminated in consolidation.

Gathering, transportation and other expenses attributable to our midstream segment increased $1.6 million for the nine months ended September 30, 2010 compared to the same period in 2009. The increase was primarily due to the increase in throughput associated with the continued development of our gathering systems and treating facilities primarily in the Haynesville and Eagle Ford Shales. Gathering and treating throughput increased 37.9 Bcf to 184.9 Bcf for the nine months ended September 30, 2010 compared to 147.0 Bcf for the nine months ended September 30, 2009, which includes 61.0 Bcf of Haynesville treating throughput. The increase in throughput was partially offset by the contribution of the gas gathering systems and treating facilities in the Haynesville Shale to KinderHawk.

General and administrative expense for the nine months ended September 30, 2010 increased $41.5 million as compared to the same period in 2009. Contributing to the increase were various costs associated with the closing of our joint venture with Kinder Morgan including a $7.5 million payment we made for services to our advisors on the KinderHawk formation transaction. Our legal expense increased $17.3 million from the same period in 2009 for legal fees associated with our ongoing legal matters, as well as various legal settlements. The remaining $16.7 million increase was primarily attributable to an increase in payroll and employee costs, including salaries, benefits and incentives associated with the building of our work force as a result of the continued growth in our Company.

Depletion for oil and natural gas properties is calculated using the unit of production method, which depletes the capitalized costs associated with 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 $23.3 million for the nine months ended September 30, 2010 from the same period in 2009, to $302.4 million. On a per unit basis, depletion expense decreased $0.46 per Mcfe to $1.72 per Mcfe. The decrease on a per unit basis is primarily due to the ceiling test impairment write-downs of $1.7 billion we recorded at March 31, 2009 and $106 million at December 31, 2009, as well as our property sales in 2009 and 2010.

Depreciation expense associated with our gas gathering systems decreased $0.3 million to $7.8 million for the nine months ended September 30, 2010. The $0.3 million decrease was primarily due to the contribution of the gas gathering systems and treating facilities in the Haynesville Shale to KinderHawk, partially offset by the current year expansion of our Eagle Ford gas gathering and treating system.

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. 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. For the first three quarters of 2009, we calculated the ceiling using prevailing oil and natural gas prices on the last day of the period, or a subsequent higher price under certain circumstances. At March 31, 2009, our ceiling was calculated using prices of $49.66 per barrel of oil and $3.63 per Mmbtu for natural gas. Accordingly, at March 31, 2009, our costs exceeded our ceiling limitation by approximately $1.7 billion, resulting in an approximate $1.7 billion writedown of our oil and natural gas properties before income taxes.

On May 21, 2010, we contributed our Haynesville Shale gathering and treating business in exchange for a 50% membership interest in a new joint venture entity, KinderHawk, and approximately $921 million in cash. At May 21, 2010, as a result of this transaction, we recorded a deferred gain of approximately $713.8 million for the difference between 50% of the net carrying value of the assets we contributed to the joint venture and the net cash proceeds from KinderHawk, representing the cash contributed by Kinder Morgan at closing for its 50% membership interest in KinderHawk. We will recognize the portion of the deferred gain equal to our capital commitment over the remainder of 2010 and 2011 as contributions to KinderHawk are made or upon expiration. In addition to the capital commitment, we guaranteed to deliver certain minimum volumes of natural gas through the Haynesville Shale gathering system for the next five years. We will recognize the remaining deferred gain as volumes are delivered through the Haynesville Shale gathering system over the next five years. During the nine months ended September 30, 2010, the Company recognized $123.8 million of the deferred gain.

We enter into derivative commodity instruments to economically hedge our exposure to price fluctuations on our anticipated oil and natural gas production. Historically, we have also entered into interest rate swaps to mitigate exposure to market rate fluctuations by converting variable interest rates (such as those on our Senior Credit Agreement) to fixed interest rates. 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 unaudited condensed consolidated statement of operations. At September 30, 2010, we had a $370.5 million derivative asset, $275.9 million of which was classified as current, and a $2.5 million derivative liability, $0.7 million of which was classified as current. We recorded a net derivative gain of $346.0 million ($190.2 million net unrealized gain and $155.8 million net gain for cash received on settled contracts) for the nine months ended September 30, 2010 compared to a net derivative gain of $196.4 million ($96.7 million net unrealized loss and a $293.1 million gain for cash received on settled contracts) in the same period in 2009.

Interest expense and other increased $64.2 million for the nine months ended September 30, 2010. This increase was primarily due to the early repurchase of the 2013 Notes in which, we incurred charges of approximately $47.1 million in 2010. Also contributing to the increase was the increased utilization of our Senior Credit Agreement and a decrease in capitalized interest.

Our investment in KinderHawk in which we do not have a majority interest, but do have significant influence, is accounted for under the equity method. Under the equity method of accounting, our share of net income (loss) from KinderHawk is reflected as an increase (decrease) in our investment account and is also recorded as equity investment income (loss). Distributions from KinderHawk are recorded as reductions of our investment and contributions to KinderHawk are recorded as increases of our investment. Our net share of KinderHawk s earnings or losses is reported as *Equity investment income* in the unaudited condensed consolidated statements of operations. For the nine months ended September 30, 2010, our net share of KinderHawk s income was $10.6 million.

We had an income tax provision of $170.6 million for the nine months ended September 30, 2010 due to our pre-tax income of $438.9 million compared to an income tax benefit of $650.2 million due to our pre-tax loss of $1.7 billion in the prior year. The effective tax rate for the nine months ended September 30, 2010 was 38.9% compared to 38.0% for the nine months ended September 30, 2009. The change in the effective tax rate is primarily due to the increase in our state tax rate generated by a shift in the composition of assets among various states.

Recently Issued Accounting Pronouncements

We discuss recently adopted and issued accounting standards in Item 1. *Condensed Consolidated Financial Statements (Unaudited)* 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, natural gas and natural gas liquids 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, and put options. 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 for the next 12 to 36 months. Our hedge policies and objectives may change significantly as commodities prices or price futures change.

We are exposed to market risk on our open derivative contracts of non-performance by our counterparties. We do not expect such non-performance because our contracts are with major financial institutions with investment grade credit ratings. Each of the counterparties to our derivative contracts is a lender in our Senior Credit Agreement. We did not post collateral under any of these contracts as they are secured under the Senior Credit Agreement. Please refer to Item 1. *Condensed Consolidated Financial Statements (Unaudited)* 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 September 30, 2010, 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.

We account for our derivative activities under the provisions of ASC 815, *Derivatives and Hedging* (ASC 815). ASC 815 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 (Unaudited)* Note 8, *Derivatives* for more details.

Interest Sensitivity

We are exposed to market risk related to adverse changes in interest rates. Our interest rate risk exposure results primarily from fluctuations in short-term rates, which are LIBOR and ABR based and may result in reductions of earnings or cash flows due to increases in the interest rates we pay on these obligations.

At September 30, 2010, total long-term debt was $2.6 billion, of which approximately 95% bears interest at a weighted average fixed interest rate of 8.2% per year. The remaining 5% of our total debt balance at September 30, 2010 bears interest at floating or market interest rates that at our option are tied to prime rate or LIBOR. Fluctuations in market interest rates will cause our annual interest costs to fluctuate. At September 30, 2010, the interest rate on our variable rate debt was 3.5% per year. If the balance of our variable rate debt at September 30, 2010 were to remain constant, a 10% change in market interest rates would impact our cash flow by approximately $0.1 million per quarter.

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 September 30, 2010 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 Securities and Exchange Commission (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 primarily 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 constructed 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. 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.

We are also involved in natural gas exploration in the Haynesville Shale play in Louisiana. 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, and Red River Parishes in Louisiana. On approximately December 14, 2009, the United States Environmental Protection Agency (EPA) informed us that it would be acting as lead enforcement agency regarding these alleged violations. We have identified additional well sites on

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which work may have been conducted without required authorizations under the Clean Water Act. Information related to these well sites has been disclosed to the Corps of Engineers and the EPA. We are investigating these allegations and are unable at this time to estimate our potential exposure related to this matter. As of this date our investigation has identified 36 additional well sites on which work was commenced while permits were still pending before the Corps of Engineers. All of this information has been disclosed to the Corps of Engineers and EPA. 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.

On May 14, 2010, Hawk Field Services was notified by the ADEQ of alleged violations of Arkansas air quality permits at eight sites in the Fayetteville Shale play. The majority of the alleged violations relate to a failure to conduct and submit testing associated with bringing new equipment online in a timely manner and other documentation issues. Hawk Field Services has responded to the ADEQ regarding the alleged violations. At this point, we are unable to estimate Hawk Field Service s potential exposure in connection with these alleged violations. Hawk Field Services could, however, be required to pay a monetary penalty and be required to implement certain management practices.

Item 1A. Risk Factors

There have been no material changes to the risk factors described in the Company s Annual Report on Form 10-K, for the year ended December 31, 2009, except as stated below.

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

Legislation has been proposed in Congress 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 oil and natural gas production. We engage third parties to provide hydraulic fracturing or other well stimulation services to us in connection with many of the wells for which we are the operator. Sponsors of bills currently pending before the Senate and House of Representatives have asserted that chemicals used in the fracturing process may be adversely impacting 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 are impairing groundwater or causing other damage. These bills, if adopted, could establish an additional level of regulation at the federal or state 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. Certain states have adopted or are considering similar disclosure legislation.

In March 2010, the United States Environmental Protection Agency announced that it would conduct a wide-ranging study on the effects of hydraulic fracturing on human health and the environment. The agency also announced that one of its enforcement initiatives for 2011 to 2013 would be to focus on environmental compliance by the energy extraction sector. This study and enforcement initiative could result in additional regulatory scrutiny that could make it difficult to perform hydraulic fracturing and increase our costs of compliance and doing business.

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

Our 2009 Annual Report on Form 10-K includes, and our other filings with the SEC may include, estimates of 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, 2009, approximately 67% 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.

Recent federal legislation could have an adverse impact on our ability to use derivative instruments to reduce the effects of commodity prices, interest rates and other risks associated with our business.

We enter into a number of commodity derivative contracts in order to hedge a portion of our oil and natural gas production and, periodically, interest expense. On July 21, 2010, President Obama signed into law the Dodd-Frank Wall Street Reform and Consumer Protection Act, or the Dodd-Frank Act. Title VII of the Dodd-Frank Act (titled Wall Street Transparency and Accountability) repeals prior regulatory exemptions for over-the-counter (OTC) derivatives and, for the first time, creates a comprehensive framework for the regulation of the derivatives market and, in connection therewith, expands the power of the Securities and Exchange Commission and, in particular, the Commodity Futures Trading Commission (or CFTC). Among the provisions of the Dodd-Frank Act that may affect derivatives transactions are certain clearing and trade-execution requirements; establishing capital and margin requirements for certain derivatives participants; establishing business conduct standards, recordkeeping and reporting requirements; and providing the CFTC with authority to impose position limits in the OTC derivatives markets. The Dodd-Frank Act may require the counterparties to our derivative instruments to spin off some of their derivatives activities to a separate entity, which may not be as creditworthy as the current counterparty. The new legislation and any new regulations could significantly increase the cost of derivative contracts (including requirements to post collateral which could adversely affect our available liquidity), materially alter the terms of derivative contracts, reduce the availability of derivatives to protect against risks we encounter, reduce our ability to monetize or restructure our existing derivative contracts, and increase our exposure to less creditworthy counterparties.

Many of the key concepts and processes under the Dodd-Frank Act are not defined and must be delineated by rules and regulations to be adopted by applicable regulatory agencies. As a consequence, it is not possible at this time to predict the effects that the Dodd-Frank Act or these new rules and regulations may have on our hedging activities. To the extent that we are subject to capital or margin requirements relating to, or restrictions on, our hedging activities or the costs associated with hedging activities increase, it could have an adverse effect on our ability to hedge the risks associated with our business, our results of operations may become more volatile and our cash flows may be less predictable, which could adversely affect our ability to plan for and fund capital expenditures. Finally, the legislation was intended, in part, to reduce the volatility of oil and natural gas prices, which some legislators attributed to speculative trading in derivatives and commodity instruments related to oil and natural gas. If a consequence of the legislation and regulations is to lower commodity prices, our revenues could be adversely affected. Any of these consequences could have a material, adverse effect on us, our financial condition, and our results of operations.

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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 September 30, 2010.

	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
July 2010	1,381	$ 17.23		
August 2010	4,318	16.06		
September 2010	1,009	15.71		

(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. (Removed and Reserved)

Item 5. Other Information

None.

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Item 6. Exhibits

The following documents are included as exhibits to this Quarterly Report on 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).
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).

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Exhibit No	Description
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).
4.11	Seventh Supplemental Indenture dated as of August 4, 2009 among Kaiser Trading, LLC, Petrohawk Energy Corporation, the existing Guarantors, and Law Debenture Trust Company of New York, as the successor to U.S. Bank National Association, as trustee (Incorporated by reference to Exhibit 4.11 to our Quarterly Report on Form 10-Q filed on November 9, 2009).
4.12	Eighth Supplemental Indenture dated as of June 30, 2010 among Big Hawk Services, LLC, Petrohawk Energy Corporation, the existing Guarantors, and 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 August 3, 2010).
4.13	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).
4.14	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).
4.15	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).

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Exhibit No	Description
4.16	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).
4.17	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).
4.18	Fifth Supplemental Indenture dated as of August 4, 2009 among Kaiser Trading, LLC, Petrohawk Energy Corporation, the existing Guarantors, and U.S. Bank National Association, as trustee (Incorporated by reference to Exhibit 4.17 to our Quarterly Report on Form 10-Q filed on November 5, 2009).
4.19	Sixth Supplemental Indenture dated as of June 30, 2010 among Big Hawk Services, LLC, Petrohawk Energy Corporation, the existing Guarantors, and U.S. Bank National Association, as trustee (Incorporated by reference to Exhibit 4.19 to our Quarterly Report on Form 10-Q filed on August 3, 2010).
4.20	Sixth Supplemental Indenture, dated as of August 17, 2010 among Petrohawk Energy Corporation, the guarantors named therein and U.S. Bank National Association, as Trustee (Incorporated by reference to Exhibit 4.3 to our Current Report on Form 8-K filed on August 20, 2010).
4.21	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).
4.22	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).
4.23	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).
4.24	Third Supplemental Indenture dated as of August 4, 2009 among Kaiser Trading, LLC, Petrohawk Energy Corporation, the existing Guarantors, and U.S. Bank Trust National Association, as trustee (Incorporated by reference to Exhibit 4.21 to our Quarterly Report on Form 10-Q filed on November 5, 2009).
4.25	Fourth Supplemental Indenture dated as of June 30, 2010 among Big Hawk Services, LLC, Petrohawk Energy Corporation, the existing Guarantors, and U.S. Bank Trust National Association, as trustee (Incorporated by reference to Exhibit 4.24 to our Quarterly Report on Form 10-Q filed on August 3, 2010).
4.26	Indenture, dated January 27, 2009, among the Petrohawk Energy Corporation, 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).
4.27	First Supplemental Indenture, dated August 4, 2009, among the Kaiser Trading, LLC, Petrohawk Energy Corporation, the existing Guarantors, and U.S. Bank Trust National Association, as trustee (Incorporated by reference to Exhibit 4.26 to our Quarterly Report on Form 10-Q filed on November 5, 2009).

Exhibit No	Description
4.28	Second Supplemental Indenture, dated June 30, 2010, among the Big Hawk Services, LLC, Petrohawk Energy Corporation, the existing Guarantors, and U.S. Bank Trust National Association, as trustee (Incorporated by reference to Exhibit 4.19 to our Quarterly Report on Form 10-Q filed on August 3, 2010).
4.29	Indenture, dated as of August 17, 2010, among Petrohawk Energy Corporation, the guarantors named therein and U.S. Bank National Association, as Trustee (Incorporated by reference to Exhibit 4.1 to our Current Report on Form 8-K filed on August 20, 2010).
4.30	Registration Rights Agreement, dated as of August 17, 2010, among Petrohawk Energy Corporation and Barclays Capital Inc., on behalf the initial purchasers named therein (Incorporated by reference to Exhibit 4.2 to our Current Report on Form 8-K filed on August 20, 2010).
10.1	Fifth Amended and Restated Senior Revolving Credit Agreement dated August 2, 2010, 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 Bank of Montreal, as co-syndication agents for the Lenders, and JPMorgan Chase Bank, N.A. and Wells Fargo Bank, N.A., as co-documentation agents for the Lenders (Incorporated by reference to Exhibit 10.1 of our Current Report on Form 8-K filed on August 3, 2010).
10.2	Fifth Amended and Restated Guarantee and Collateral Agreement dated August 2, 2010, 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 August 3, 2010).
10.3	The Petrohawk Energy Corporation Second Amended and Restated 2004 Non-Employee Director Incentive Plan (Incorporated by reference to Exhibit 10.2 of our Current Report on Form 8-K filed on June 23, 2009).
10.4	Form of Restricted Stock Agreement for the Second Amended and Restated 2004 Non-Employee Director Incentive Plan (Incorporated by reference to Exhibit 10.4 of our Second Quarter 2005 Form 10-Q filed on August 11, 2005).
10.5	The Petrohawk Energy Corporation Third Amended and Restated 2004 Employee Incentive Plan (Incorporated by reference to Exhibit 10.1 of our Current Report on Form 8-K filed June 23, 2009).
10.6	Form of Stock Option Agreement for the Third Amended and Restated 2004 Employee Incentive Plan (Incorporated by reference to Exhibit 10.3 of our Annual Report on Form 10-K filed March 14, 2006).
10.7	Form of Restricted Stock Agreement for the Third Amended and Restated 2004 Employee Incentive Plan (Incorporated by reference to Exhibit 10.8 of our Second Quarter 2005 Form 10-Q filed on August 11, 2005).
10.8	Purchase Agreement dated August 3, 2010, among the Company and Barclays Capital Inc., on behalf of Barclays Capital Inc., J.P. Morgan Securities, Inc., Wells Fargo Securities, LLC, Banc of America Securities LLC, BMO Capital Markets Corp., BNP Paribas Securities Corp., Credit Suisse Securities (USA) LLC, RBC Capital Markets Corporation, Credit Agricole Securities (USA) LLC, Morgan Stanley & Co. Incorporated, Capital One Southcoast, Inc., Citigroup Global Markets Inc., Mizuho Securities USA Inc., and Natixis Bleichroeder LLC (Incorporated by reference to Exhibit 10.1 of our Current Report on Form 8-K filed August 6, 2010).
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 the Sarbanes-Oxley Act of 2002

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Exhibit No	**Description**
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: November 2, 2010

By: /s/ Floyd C. Wilson
Floyd C. Wilson
Chairman of the Board 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