PETROHAWK ENERGY CORP
Form 10-K
February 22, 2011

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ITEM 8. CONSOLIDATED FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

UNITED STATES
SECURITIES AND EXCHANGE COMMISSION

WASHINGTON, D.C. 20549

FORM 10-K

ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934

For the fiscal year ended December 31, 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 if the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act. Yes ý No o

Indicate by check mark if the registrant is not required to file reports pursuant to Section 13 or Section 15(d) of the Act. Yes o No ý

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months and (2) has been subject to such filing requirements for the past 90 days. Yes ý No o

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 ý No o

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K is not contained herein, and will not be contained, to the best of registrant's knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K. o

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

Large accelerated filer ý Accelerated filer o Non-accelerated filer o Smaller reporting company o

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

The aggregate market value of common stock, par value $.001 per share, held by non-affiliates (based upon the closing sales price on the New York Stock Exchange on June 30, 2010), the last business day of registrant's most recently completed second fiscal quarter was approximately $5.1 billion.

As of February 17, 2011, there were 302,463,105 shares of common stock outstanding.

DOCUMENTS INCORPORATED BY REFERENCE

Information required by Part III, Items 10, 11, 12, 13 and 14, is incorporated by reference to portions of the registrant's definitive proxy statement for its 2011 annual meeting of stockholders which will be filed on or before April 30, 2011.

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Special note regarding forward-looking statements

This Annual Report on Form 10-K 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 and location of wells to be drilled in the future, future cash flows and borrowings, pursuit of potential acquisition opportunities, our financial position, business strategy and other plans and objectives for future operations, are forward-looking statements. These forward-looking statements are identified by their use of terms and phrases such as "may," "expect," "estimate," "project," "plan," "believe," "intend," "achievable," "anticipate," "will," "continue," "potential," "should," "could" and similar terms and phrases. Although we believe that the expectations reflected in these forward-looking statements are reasonable, they do involve certain assumptions, risks and uncertainties. Actual results could differ materially from those anticipated in these forward-looking statements. One should consider carefully the statements under the "Risk Factors" section of this report and other sections of this report 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 in our resource plays such as the Haynesville, Lower Bossier and Eagle Ford Shales;
- volatility in commodity prices for oil and natural gas;
- the possibility that the 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 play holdings;
- management's ability to execute our plans to meet our goals;
- our ability to retain key members of senior management and key technical employees;

the cost and availability of goods and services, such as drilling rigs, fracture stimulation services and tubulars;

access to and availability of water and other treatment materials to carry out planned fracture stimulations in our resource plays;

access to adequate gathering systems and transportation take-away capacity, necessary to fully execute our capital program;

our ability to secure firm transportation and other marketing outlets for the natural gas, natural gas liquids and crude oil and condensate we produce and to sell these products at market prices;

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- 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 economic conditions in the United States will worsen and that capital markets are disrupted, which could adversely affect demand for oil and natural gas and make it difficult to access financial markets;

- social unrest, political instability or armed conflict in oil and natural gas producing regions, such as the Middle East, and armed conflict 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.

Finally, our future results will depend upon various other risks and uncertainties, including, but not limited to, those detailed in the section entitled "Risk Factors" included in this report. 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

ITEM 1. BUSINESS

Overview

We are an independent oil and natural gas company engaged in the exploration, development and production of predominately natural gas properties located 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 three premier domestic shale plays that we believe have decades of future development potential. We organize our oil and natural gas operations into two principal regions: the Mid-Continent, which includes our Louisiana and East Texas properties; and the Western, which includes our South Texas properties. Our midstream segment consists of our wholly owned gathering and treating subsidiary, Hawk Field Services, LLC (Hawk Field Services). We formed Hawk Field Services to enhance shareholder value by integrating our active drilling program with activities of third parties to develop additional gathering and treating capacity. Hawk Field Services currently serves the Haynesville Shale and Lower Bossier Shale in North Louisiana through our investment in KinderHawk Field Services, LLC (KinderHawk) and the Eagle Ford Shale in South Texas.

At December 31, 2010, our estimated total proved oil and natural gas reserves, as prepared by our independent reserve engineering firm, Netherland, Sewell & Associates, Inc. (Netherland, Sewell), were approximately 3,392 billion cubic feet of natural gas equivalent (Bcfe), consisting of 3,110 billion cubic feet (Bcf) of natural gas, 20 million barrels (MMBbls) of oil, and 27 MMBbls of natural gas liquids. Approximately 35% of our proved reserves were classified as proved developed. We maintain operational control of approximately 82% of our proved reserves. Production for the fourth quarter of 2010 averaged 761 million cubic feet of natural gas equivalent (Mmcfe) per day (Mmcfe/d). Full year 2010 production averaged 675 Mmcfe/d compared to 502 Mmcfe/d in 2009. Our total operating revenues for 2010 were approximately $1.6 billion.

We focus on properties within our core operating areas that 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 unit lease operating costs. We continue to selectively expand our leasehold position in our existing resource plays in the Haynesville and Lower Bossier Shales in North Louisiana and the Eagle Ford Shale in South Texas. We expect to continue to grow our production and reserves from these existing areas, with a near-term focus on holding our acreage positions and growing our crude oil and natural gas liquids production. We also expect to continue to evaluate new entry in areas that may be prospective for the resource plays we seek in order to capitalize on our expertise and extensive experience.

Recent Developments

2012 Note Refinancing

On January 31, 2011, we completed the issuance of an additional $400 million aggregate principal amount of our 7.25% senior notes due 2018 (the 2018 Notes). We will utilize a portion of the proceeds from this issuance to redeem our $275 million 7.125% senior notes, which have been called for redemption.

Senior Revolving Credit Facility

Effective August 2, 2010, we amended and restated our existing credit facility dated October 14, 2009 by entering into the Fifth Amended and Restated Senior Revolving Credit Agreement (the Senior Credit Agreement), among us, 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 December 31, 2010, the borrowing base was approximately $1.65 billion, $1.55 billion of which related to our oil and natural gas properties and up to $100 million (currently limited as described below) related to our midstream assets. The portion of the borrowing base relating to our oil and natural gas properties is redetermined on a semi-annual basis (with us 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 relating to our midstream assets is limited to the lesser of $100 million or 3.5 times midstream earnings before interest, taxes, depreciation and amortization (EBITDA), and is calculated quarterly. As of December 31, 2010, the midstream component of the borrowing base was limited to approximately $38 million based on midstream EBITDA. Our 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 unsecured senior or senior subordinated notes that we may issue. In January 2011, we issued an additional $400 million aggregate principal amount of our 7.25% senior notes, a portion of the proceeds of which will be used to redeem all of our 7.125% $275 million senior notes, which have been called for redemption. Accordingly, our borrowing base was reduced to approximately $1.6 billion.

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 our 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, our subsidiaries. Amounts drawn on the facility will mature on July 1, 2014.

Fayetteville Shale Divestiture

On December 22, 2010, we completed the sale of our interest in natural gas properties and other operating assets in the Fayetteville Shale for $575 million in cash, before customary closing adjustments. As part of the transaction, the buyer also assumed certain firm pipeline transportation obligations of approximately $100 million. As of December 31, 2009, we had approximately 299 Bcf of proved reserves associated with the Fayetteville Shale. Production from the Fayetteville Shale as of the sale date was approximately 98 Mmcfe/d. Proceeds from the sale of the natural gas properties were recorded as a reduction to the carrying value of our full cost pool with no gain or loss recorded. In conjunction with the sale of the other operating assets, we recorded a loss of approximately $0.5 million in the year ended December 31, 2010. On January 7, 2011, we completed the sale of our midstream assets in the Fayetteville Shale for $75 million in cash, before customary closing adjustments. As of December 31, 2010, the Fayetteville Shale midstream assets were classified as held for sale on our consolidated balance sheet. Assets held for sale were recorded at the lesser of the carrying amount or the fair value less costs to sell, which resulted in a write down of the carrying amount of approximately $69.7 million before income taxes in the year ended December 31, 2010, which is included in *"Loss from discontinued operations net of income taxes"* on the consolidated statements of operations. Both transactions had an effective date of October 1, 2010.

2013 Note Refinancing

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 redeem 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 redemption of the 2013 Notes, we incurred charges of approximately $47 million in the third quarter of 2010. These charges are recorded in *"Interest expense and other"* on the consolidated statements of operations and include the cash premium paid to noteholders for the early redemption 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.

Mid-Continent Properties Divestiture

On September 29, 2010, we completed the sale of our 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 our full cost pool with no gain or loss recorded. The transaction had an effective date of July 1, 2010.

Hawk Field Services, LLC Joint Venture

On May 21, 2010, 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 joint venture pursuant to a Formation and Contribution Agreement (Contribution Agreement). The joint venture entity, KinderHawk, engages in the natural gas midstream business in Northwest Louisiana, focused on the Haynesville and Lower Bossier Shales. Pursuant to the Contribution Agreement, Hawk Field Services contributed to KinderHawk its Haynesville Shale gathering and treating business in Northwest Louisiana, and Kinder Morgan contributed approximately $917 million in cash ($875 million for a 50% membership interest in KinderHawk and $42 million for certain closing adjustments including 2010 capital expenditures through the closing date) to KinderHawk. Hawk Field Services and Kinder Morgan each own a 50% membership interest in KinderHawk. KinderHawk distributed approximately $917 million to Hawk Field Services. The joint venture had an economic effective date of January 1, 2010, and Hawk Field Services continued to operate the business until September 30, 2010, at which date Hawk Field Services 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 to KinderHawk agreed upon minimum annual quantities of natural gas from our operated wells producing from the Haynesville and Lower Bossier Shales, within specified acreage in Northwest Louisiana through May 2015, 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 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.

As a result of this transaction, we recorded a deferred gain of approximately $719.4 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 as contributions to KinderHawk are made or upon expiration of the capital commitment at December 31, 2011. In addition to the capital commitment, we guaranteed to deliver certain minimum volumes of natural gas through the Haynesville Shale gathering system through May 2015. We will recognize the remaining deferred gain as volumes are delivered through the Haynesville Shale gathering system through May 2015.

Terryville Divestiture

On May 12, 2010, we completed the sale of our interest in the Terryville Field, located in Lincoln and Claiborne Parishes, Louisiana for $320 million in cash, before customary closing adjustments. As of December 31, 2009, we had approximately 100 Bcfe of proved reserves associated with the Terryville Field. Production from the Terryville Field as of the sale date was approximately 20 Mmcfe/d. Proceeds

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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.

West Edmond Hunton Lime Unit Divestiture

On April 30, 2010, we completed the sale of our interest in the West Edmond Hunton Lime Unit (WEHLU) Field in Oklahoma County, Oklahoma for $155 million in cash, before customary closing adjustments. As of December 31, 2009, we had approximately 23 Bcfe of proved reserves associated with the WEHLU Field. Production from the WEHLU Field as of the sale date was approximately 12 Mmcfe/d. 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.

Acreage Acquisitions

During 2010, we completed acquisitions of acreage for a total of approximately $635 million. Leasehold acquisitions for 2010 included approximately $420 million in the Eagle Ford Shale, primarily in the Black Hawk area, approximately $141 million in the Haynesville Shale and approximately $74 million in other areas.

2011 Capital budget

We expect to spend approximately $2.3 billion during 2011, of which $1.9 billion is expected to be allocated for drilling and completions, $200 million is expected to be allocated for midstream operations and $200 million will be allocated for potential leasehold acreage acquisitions. Of the $1.9 billion budget for drilling and completions, $900 million is planned for the Haynesville and Lower Bossier Shales, which will enable us to fulfill our lease capture goals, $900 million is budgeted for the Eagle Ford Shale, and approximately $100 million is budgeted for various other projects. Our 2011 drilling and completion budget 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 as our lease-holding activities are fulfilled. Our 2011 program will emphasize the development of our extensive condensate-rich properties, largely in the Eagle Ford Shale, and a shift away from dry gas development. The $1.9 billion drilling and completion budget for 2011 is based on our current view of market conditions, our ability 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.

We expect to fund our 2011 capital budget with cash flows from operations, proceeds from potential asset dispositions, a portion of the proceeds from our recent senior note offering and borrowings under our Senior Credit Agreement. We strive to maintain financial flexibility and may access capital markets as necessary to 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. In the event our cash flows or proceeds from potential asset dispositions are materially less than anticipated and other sources of capital we historically have utilized are not available on acceptable terms, we may curtail our capital spending.

Business Strategy

Our primary objective is to increase stockholder value by exploiting resource plays within our established core areas and exploring for new unconventional plays. We leverage our technical expertise in tight-gas and shale reservoirs to establish and develop large-scale operations in some of the fastest growing shale plays in the country. Once we establish an area as core, we focus on aggressively developing the asset through cost-effective drilling, active reservoir management, infrastructure optimization, and selected leasehold expansion and highgrading. Our operations offer the potential for predictable, long-term production with low costs achieved through effective drilling and completions techniques, efficient field management and scalable operations. Our strategy emphasizes:

Concentrated portfolio of properties We currently hold a high-quality portfolio of properties within a limited number of core plays, notably the Haynesville, Lower Bossier and Eagle Ford Shales. We believe we have significant exploitation and development opportunities in these plays where we can apply our technical experience and economies of scale to achieve profitable future growth. Currently our portfolio is more heavily weighted toward natural gas; however, in the future we expect our product mix to shift toward a greater percentage of liquids, especially as our Eagle Ford Shale programs increase.

Attractive undeveloped reserves We seek to maintain a portfolio of long-lived properties focused on resource plays within our core operating areas. Resource plays are typically characterized by lower geological risk and a large inventory of identified drilling opportunities. Our current plays include the Haynesville and Lower Bossier Shales in North Louisiana and East Texas and the Eagle Ford Shale in South Texas. We believe these properties have the potential to contribute significant growth in production and reserves over the long term.

Reduce operating costs We focus on reducing the per unit operating costs associated with our properties and have been successful in lowering our unit lease operating expenses from $0.47 Mcfe in 2008 to $0.43 per Mcfe in 2009 and $0.26 per Mcfe in 2010, including $0.22 per Mcfe during the fourth quarter.

Divestment of non-core properties We continually evaluate our property portfolio to identify opportunities to divest non-core, higher cost or less productive properties with limited development potential. This highgrading strategy allows us to achieve a more concentrated portfolio of core properties with significant potential to increase our proved reserves and production and reduce our per unit operating costs. To allow us to concentrate on our core properties and further enhance our liquidity position, in 2010 we contributed our Haynesville Shale midstream business to a joint venture, and sold our interest in the Terryville Field in Northwest Louisiana, the WEHLU Field in central Oklahoma, and the Fayetteville Shale in Arkansas, as well as divested other non-core assets in the Mid-Continent region. Total proceeds from 2010 divestitures were approximately $2.1 billion.

Maintenance of financial flexibility We strive to maintain financial flexibility by balancing our financial resources with our plans to develop our key properties and pursue opportunities for growth and expansion. We intend to maintain substantial borrowing capacity under our Senior Credit Agreement to facilitate drilling on our large undeveloped acreage position in resource plays, selectively expand our position in these and other emerging resource plays and expand our infrastructure projects. We may access capital markets as necessary to maintain substantial borrowing capacity under our Senior Credit Agreement. We hedge a substantial portion of our production to provide downside price protection.

Oil and Natural Gas Reserves

Estimates of proved reserves at December 31, 2010, 2009, and 2008 were prepared by Netherland, Sewell & Associates, Inc., our independent consulting petroleum engineers. The technical persons responsible for preparing the reserve estimates are independent petroleum engineers and geoscientists that meet the requirements regarding qualifications, independence, objectivity, and confidentiality set forth in the Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information promulgated by the Society of Petroleum Engineers. Our board of directors has established an independent reserves committee composed of three outside directors, all of whom have experience in energy company reserve evaluations. Our independent engineering firm reports jointly to the reserves committee and to our Senior Vice President Corporate Reserves. The reserves committee is charged with ensuring the integrity of the process of selection and engagement of the independent engineering

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firm and in making a recommendation to our board of directors as to whether to accept the report prepared by our independent consulting petroleum engineers. For information regarding the experience and qualifications of the members of the reserves committee of our board of directors and our Senior Vice President Corporate Reserves, see Item 10*Directors, Executive Officers and Corporate Governance.*

The reserves information in this Annual Report on Form 10-K represents only estimates. There are a number of uncertainties inherent in estimating quantities of proved reserves, including many factors beyond our control, such as commodity pricing. Reserve engineering is a subjective process of estimating underground accumulations of oil and natural gas that cannot be measured in an exact manner. The accuracy of any reserve estimate is a function of the quality of available data and of engineering and geological interpretation and judgment. As a result, estimates of different engineers may vary. In addition, results of drilling, testing and production subsequent to the date of an estimate may lead to revising the original estimate. Accordingly, initial reserve estimates are often different from the quantities of oil and natural gas that are ultimately recovered. The meaningfulness of such estimates depends primarily on the accuracy of the assumptions upon which they were based. Except to the extent we acquire additional properties containing proved reserves or conduct successful exploration and development activities or both, our proved reserves will decline as reserves are produced. For additional information regarding estimates of proved reserves, the preparation of such estimates by Netherland, Sewell and other information about our oil and natural gas reserves, see Item 8. *Consolidated Financial Statements and Supplementary Data* "*Supplemental Oil and Gas Information (Unaudited)*."

Proved reserve estimates are based on the unweighted arithmetic average prices on the first day of each month for the 12-month period ended December 31, 2010. Average prices for the 12-month period were as follows: West Texas Intermediate (WTI) spot price of $79.43 per barrel (Bbl) for oil and natural gas liquids, adjusted by lease or field for quality, transportation fees, and regional price differentials and a Henry Hub spot market price of $4.38 per million British thermal unit (Mmbtu) for natural gas, as adjusted by lease or field for energy content, transportation fees, and regional price differentials. All prices and costs associated with operating wells were held constant in accordance with the amended United States Securities and Exchange Commission (SEC) guidelines which were effective for financial statements for periods ending on or after December 31, 2009. The following table presents certain information as of December 31, 2010.

	Mid-Continent Region	**Western Region**	**Total**
Proved Reserves at Year End (Bcfe)[(1)]			
Developed	1,018.2	166.0	1,184.2
Undeveloped	1,637.4	570.0	2,207.4
Total	2,655.6	736.0	3,391.6

(1) *Oil and natural gas liquids are converted to equivalent gas reserves with 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.*

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The following table sets forth the number of productive oil and natural gas wells in which we owned an interest as of December 31, 2010 and 2009. Shut-in wells currently not capable of production are excluded from producing well information.

	Years Ended December 31,			
	2010		2009	
	Gross	Net(1)	Gross	Net(1)
Oil	2.0	1.8	343.0	72.8
Natural Gas	2,814.0	1,281.7	4,687.0	1,703.2
Total	2,816.0	1,283.5	5,030.0	1,776.0

(1) *Net wells represent our working interest share of each well. The term "net" as used in "net acres" or "net production" throughout this document refers to amounts that include only acreage or production that we own and produce to our interest, less royalties and production due to others.*

Operating Segments

During the fourth quarter of 2009, we made a strategic shift in focus on and allocation of resources to our midstream division. As a result, we identified two reportable segments: oil and natural gas production and midstream operations. A further description of our operating segments is included in Item 8. *Consolidated Financial Statements and Supplementary Data* Note 13, "*Segments".*

Oil and Natural Gas Production

Core Operating Regions

Mid-Continent Region

In the Mid-Continent Region, we concentrate our drilling program primarily in North Louisiana and East Texas. We believe our Mid-Continent Region operations provide us with a solid base for future production and reserve growth. During 2010, we drilled 805 wells in this region (of which 107 were operated and 698 were non-operated), and all were successful. In 2011, we plan to drill approximately 122 operated wells in this region and an additional 243 non-operated wells which are dependent upon other operators for execution. In 2010, we produced 216 Bcfe in this region, or 593 Mmcfe/d. As of December 31, 2010, approximately 78% of our proved reserves, or 2,656 Bcfe, were located in our Mid-Continent Region, which included 1,018 Bcfe of proved developed reserves. We sold our interest in natural gas properties and other operating assets in the Fayetteville Shale, which was part of our Mid-Continent Region and is located primarily in Cleburne and Van Buren Counties, Arkansas, in late December 2010 for approximately $575 million in cash, before customary closing adjustments. For further discussion of the Fayetteville Shale divestiture, see Item 1. *Business "Recent Developments."*

Haynesville Shale The Haynesville Shale has become one of the most active natural gas plays in the United States. This area is defined by a shale formation located approximately 1,500 feet below the base of the Cotton Valley formation at depths ranging from approximately 10,500 feet to 13,000 feet. The formation is as much as 300 feet thick and is composed of an organic rich black shale. It is located across numerous parishes in Northwest Louisiana, primarily in Caddo, Bossier, Red River, DeSoto, Webster and Bienville parishes and also in East Texas, primarily in Harrison, Panola, Shelby and Nacogdoches counties. Our Elm Grove/Caspiana acreage position is located near what we believe is the center of the play. We currently own leasehold interests in approximately 363,000 net acres in the area that we currently believe to be prospective for the Haynesville Shale. We own varying working and net revenue interests in this area.

Our current drilling and completion methodology focuses on completing wells with longer laterals and maximizing the number of fracture stages, averaging approximately 325 feet in

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length. The objective of this technique is to minimize the total number of wells required to effectively drain the reservoir, resulting in lower overall development costs. We are currently targeting lateral lengths between 4,300 feet and 4,800 feet with up to 15 fracture stages. At year-end 2010, we had 14 operated horizontal rigs running in the Haynesville Shale. Spud-to-first sales averaged approximately 90 days during 2010.

As of December 31, 2010, we had approximately 175 operated wells on production in North Louisiana producing approximately 694 Mmcfe/d gross. We have changed our production practice in the Haynesville Shale from one that typically produced at initial rates ranging from 18 Mmcfe/d to 24 Mmcfe/d to a typical range from 7 Mmcfe/d to 10 Mmcfe/d in an effort to maintain higher surface flowing pressures and lessen the rate of pressure decline, which we believe better maintains the permeability in the reservoir and ultimately allows for higher ultimate recovery of gas from each well. We had 10 operated wells that were pending completion and 14 operated wells that were drilling in this area at December 31, 2010.

In 2010, we produced 154 Bcfe, or 421 Mmcfe/d. As of December 31, 2010, proved reserves for this field were approximately 2,349 Bcfe, of which approximately 33% were classified as proved developed and approximately 67% as proved undeveloped. The proved reserves include 518 proved developed wells and 704 proved undeveloped locations. During 2010, we drilled 351 wells (101 operated and 250 non-operated), all of which were successful. We plan to drill 100 operated wells in this area in 2011, with eight to nine wells expected to be completed per month. We have preliminarily budgeted for an additional 230 non-operated wells in 2011 which will be dependent upon other operators for execution. We expect to operate an average of 12 rigs in the play in 2011, with an emphasis on growing production and reserves while at the same time holding our acreage position.

Lower Bossier Shale During 2010, the combination of wells we have drilled in the Haynesville Shale and wells drilled by other operators provided sufficient petrophysical and geochemical data to support the premise that there are potentially significant reserves in the Lower Bossier Shale. The Lower Bossier Shale is located approximately 200 feet to 400 feet above the Haynesville Shale. The net thickness of the shale is approximately the same as the Haynesville Shale and it also has many of the same reservoir parameters as the Haynesville Shale, particularly in the southern area of the Haynesville Shale trend. We currently own leasehold interests in approximately 150,000 net acres in the area that we currently believe to be prospective for the Lower Bossier Shale. The Whitney Corporation 19 #1H, our first Lower Bossier well, was completed in August 2010 at an initial production rate of 7.7 Mmcfe/d on a $^{14}/_{64}$" choke. We also participated in 15 Lower Bossier Shale wells as a non-operator with very positive results. We expect that it will be late 2012, and after our Haynesville Shale acreage is held by production, before we begin a significant operated Lower Bossier Shale development program. We own varying working and net revenue interests in this area. As of December 31, 2010, proved reserves for this reservoir were approximately 13 Bcfe, of which approximately 72% were classified as proved developed and approximately 28% as proved undeveloped.

Elm Grove and Caspiana Fields Located primarily in Bossier and Caddo Parishes of North Louisiana, our Elm Grove and Caspiana fields produce from the Hosston and Cotton Valley formations. These zones are composed of low permeability sandstones that require fracture stimulation treatments to produce. We currently own leasehold interests in approximately 26,000 net acres in the area that we currently believe to be prospective for Cotton Valley and/or Hosston formations. We own varying working and net revenue interests in these fields. We produced 24 Bcfe in 2010 in these fields, or 65 Mmcfe/d. As of December 31, 2010, proved reserves for the Elm Grove/Caspiana fields were approximately 290 Bcfe, of which approximately 83% were classified as proved developed, and 17% were classified as proved undeveloped. The proved reserves include 1,070 proved developed wells and 138 proved undeveloped locations. We

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owned an interest in 644 operated, producing wells in the Elm Grove and Caspiana fields as of December 31, 2010.

As this area is substantially held by production, the majority of our capital during 2010 was allocated to the Haynesville Shale as part of our plan to hold our Haynesville Shale acreage. For 2011, we will continue an allocation of capital to the Cotton Valley and Hosston program with one operated Cotton Valley formation horizontal well scheduled and a limited workover program in the Hosston formation.

Western Region

Our Western Region assets are focused primarily in the Hawkville and Black Hawk area in the Eagle Ford Shale play in South Texas. We believe our Eagle Ford Shale properties provide us with opportunities for future growth in oil, natural gas, and natural gas liquids production and reserves. During 2010 we divested other assets that the Western Region managed, including properties located in the Anadarko Basin in Oklahoma, the Arkoma Basin in Oklahoma and Arkansas and the East Texas Basin. Net production from the region was 30 Bcfe (82 Mmcfe/d) in 2010. During 2010, we drilled 69 operated wells and 32 non-operated wells with a 98% success rate. As of December 31, 2010, the proved reserves for the region were approximately 736 Bcfe of which 166 Bcfe were classified as proved developed and 570 Bcfe as proved undeveloped. There are 141 operated wells plus an additional 23 non-operated wells that are budgeted for 2011.

Hawkville Field We have approximately 236,000 net acres under lease that are located in LaSalle and McMullen Counties, Texas. Our average working interest and net revenue interest in 57 operated wells are approximately 85% and 64%, respectively. Our average working interest and net revenue interest in 12 non-operated wells are approximately 32% and 24%, respectively.
The Hawkville Eagle Ford Shale pay thickness is over 300 feet. The wells have an average true vertical depth that ranges from 10,500 feet to 12,500 feet and they are drilled with horizontal laterals currently ranging from 5,000 feet to 7,000 feet. The wells are cased hole completed and are currently being fracture stimulated with an average of 18 stages. There are currently 27 wells which produce condensate with yields ranging from six barrels per million cubic feet (Bbls/Mmcf) to 199 Bbls/Mmcf and had an average initial producing rate of 311 barrels of oil per day (Bo/d). There are currently 23 wells which produce dry gas and had an average initial producing rate of 8.6 million cubic feet of natural gas per day (Mmcf/d). We had 16 operated wells and four non-operated wells that were pending completion and three wells that were drilling in this field at year-end.

The gross operated production from this field is currently 90 Mmcf/d plus 3,500 Bo/d. As of December 31, 2010, the proved reserves were approximately 627 Bcfe of which approximately 21% were classified as proved developed and 498 Bcfe as proved undeveloped. The proved reserves include 65 proved developed wells and 203 proved undeveloped locations. During 2010, we drilled 36 operated wells and five non-operated wells with no dry holes and there are 51 operated plus 23 non-operated wells budgeted for 2011.

Black Hawk We have approximately 69,000 net acres under lease that are located in Karnes and DeWitt Counties, Texas. Petrohawk is the operator during the drilling and completion phase of the wells and a private company is the operator after the wells are placed on production. Our average working interest and net revenue interest in 27 wells are approximately 66% and 50%, respectively.

The Black Hawk Eagle Ford Shale pay thickness is over 170 feet. The wells have an average true vertical depth that ranges from 12,000 feet to 13,500 feet and they are drilled with horizontal laterals currently averaging over 5,500 feet. The wells are cased hole completed and are currently being fracture stimulated with an average of 18 stages. There are currently 12 wells which produce condensate with yields ranging from 213 Bbls/Mmcf to 517 Bbls/Mmcf and had an average initial producing rate of 1,170 Bo/d. We had 15 wells that were pending completion and five wells that were drilling in this field at December 31, 2010. The gross production from this field is currently 22 Mmcf/d plus 8,200 Bo/d. As of December 31, 2010, proved reserves were approximately 109 Bcfe of which approximately 34% were classified as proved developed and 72 Bcfe as proved undeveloped. The proved reserves include 27 proved developed wells and 41 proved undeveloped locations. During 2010, we drilled 29 wells with no dry holes and there are 85 wells budgeted for 2011.

Black Hawk Extension We acquired approximately 10,500 net acres from a private company in December 2010. This new acreage is a west/southwest extension of our existing Black Hawk acreage. We will be the operator and will have approximately 96% working interest and 79% net revenue interest in the acreage. There is currently no production on this acreage and we are expecting to spud the first well in 2012.

Red Hawk We own leases or have options on approximately 77,000 net acres that are located in Zavala County, Texas. Our working interest in this acreage ranges from 81% to 90% and our net revenue interest ranges from 61% to 68%. The Red Hawk Eagle Ford Shale pay thickness ranges from 100 feet to 140 feet. Three wells were drilled in 2010, two of which were completed and on production as of December 31, 2010. These have an average true vertical depth of 5,500 feet and they were drilled with horizontal laterals that averaged 5,500 feet. The wells are cased hole completed and were fracture stimulated with an average of 17 stages. The wells were drilled in an oil window of the Eagle Ford Shale and their initial producing rate averaged 375 Bo/d with an insignificant volume of gas. There are five wells budgeted for 2011.

Midstream Operations

During the fourth quarter of 2009, we made a strategic decision to focus on and allocate resources to our midstream division. As a result, we identified two reportable segments: oil and natural gas production and midstream operations. A further description of our operating segments is included in Item 8. *Consolidated Financial Statements and Supplementary Data* Note 13, "*Segments*". Our midstream business provides greater control over the transportation of our production for delivery into major intrastate and interstate pipelines through the access of multiple interconnects. We operate our midstream division through our subsidiary, Hawk Field Services, which constructed our own gathering systems and treating facilities to service our operated wells and third party production from the Eagle Ford, Fayetteville and Haynesville Shales.

During 2010 we expanded our gathering and treating systems in both the Haynesville Shale and Eagle Ford Shale. Approximately 214 miles of gathering pipeline and 750 gallons per minute (GPM) of treating capacity were added in the Haynesville Shale during 2010. To date, the Haynesville Shale system comprises approximately 365 miles of pipeline and 2,360 GPM of treating capacity. As of December 31, 2010, daily system throughput averaged 753 Mmcf/d. In May 2010, Hawk Field Services contributed its Haynesville Shale gathering and treating business to form a new joint venture entity with Kinder Morgan, called KinderHawk, in exchange for a 50% membership interest and approximately $917 million in cash. On January 7, 2011, we completed the sale of our midstream assets in the Fayetteville Shale for $75 million in cash, before customary closing adjustments.

Eagle Ford Shale During June 2009, we initiated construction of a high pressure gathering system in the Eagle Ford Shale to transport our production to various intrastate and interstate pipelines through the access of multiple interconnects. Our Eagle Ford Shale midstream activities have evolved into two separate midstream systems serving the Hawkville and Black Hawk areas.

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In the Hawkville area, our gathering and treating system currently consists of approximately 114 miles of 6-inch to 16-inch diameter pipeline and two treating plants. Our Hawkville area system had a throughput capacity of 550 Mmcf/d and treating capacity of 250 GPM as of December 31, 2010.

In the Black Hawk area, our system consists of approximately 42 miles of 6-inch to 16-inch diameter gas pipeline and approximately 17 miles of 4-inch to 12-inch diameter liquid pipeline. Our Black Hawk area system had a throughput capacity of 250 Mmcf/d of natural gas and 100,000 barrels per day (Bbls/d) of condensate as of December 31, 2010. We plan to continue construction of the system throughout 2011 and expect construction of our stabilization and liquid handling facility to be operational during 2011, which will treat the Black Hawk area's natural gas and stabilize condensate in preparation for delivery to end-user markets.

Risk Management

We have designed a risk management policy for the use of derivative instruments to provide partial protection against certain risks relating to our ongoing business operations, such as commodity price risk and interest rate risk. Derivative contracts are utilized to economically hedge our exposure to price fluctuations and reduce the variability in our cash flows associated with anticipated sales on future oil, natural gas and natural gas liquids production. We hedge a substantial, but varying, portion of anticipated oil, natural gas, and natural gas liquids production for the next 12 to 36 months. Periodically, we enter 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.

Our decision on the quantity and price at which we choose to hedge our production is based in part on our view of current and future market conditions. While there are many different types of derivatives available, we typically use collar agreements, swap agreements and put options to attempt to manage price risk more effectively. The collar agreements are put and call options used to establish floor and ceiling commodity prices for a fixed volume of production during a certain time period. Periodically, we may pay a fixed premium to increase the floor price above the existing market value at the time we enter into the arrangement. All collar agreements provide for payments to counterparties if the index price exceeds the ceiling and payments from the counterparties if the index price is below the floor. The price swaps call for payments to, or receipts from, counterparties based on whether the market price of oil, natural gas, and natural gas liquids for the period is greater or less than the fixed price established for that period when the swap is put in place. Under put options, we pay a fixed premium to lock in a specified floor price. If the index price falls below the floor price, the counterparty pays us net of the fixed premium. If the index price rises above floor price, we pay the fixed premium.

It is our 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 our derivative contracts is a lender in our Senior Credit Agreement. We will continue to evaluate the benefit of employing derivatives in the future. See Item 7A. *Quantitative and Qualitative Disclosures about Market Risk* for additional information.

Oil and Natural Gas Operations

Our principal properties consist of developed and undeveloped oil and natural gas leases and the reserves associated with these leases. Generally, developed oil and natural gas leases remain in force as long as production is maintained. Undeveloped oil and natural gas leaseholds are typically for a primary term of three to five years within which we are generally required to develop the property or

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the lease will expire. In some cases, the primary term of our undeveloped leases can be extended by option payments; the payments and time extended vary by lease.

The table below sets forth the results of our drilling activities for the periods indicated:

	Years Ended December 31,					
	2010		2009		2008	
	Gross	Net	Gross	Net	Gross	Net
Exploratory Wells:						
Productive[(1)]	2	1.9			2	1.8
Dry						
Total Exploratory	2	1.9			2	1.8
Extension Wells[(2)]:						
Productive[(1)]	827	192.0	601	156.8	553	181.2
Dry	2	0.6	1	0.2	12	2.0
Total Extension	829	192.6	602	157.0	565	183.2
Development Wells:						
Productive[(1)]	75	23.8	24	5.1	172	82.4
Dry						
Total Development	75	23.8	24	5.1	172	82.4
Total Wells:						
Productive[(1)]	904	217.7	625	161.9	727	265.4
Dry	2	0.6	1	0.2	12	2.0
Total	906	218.3	626	162.1	739	267.4

(1) *Although a well may be classified as productive upon completion, future changes in oil and natural gas prices, operating costs and production may result in the well becoming uneconomical, particularly extension or exploratory wells where there is no production history.*

(2) *An extension well is a well drilled to extend the limits of a known reservoir.*

We own interests in developed and undeveloped oil and natural gas acreage in the locations set forth in the table below. These ownership interests generally take the form of working interests in oil and natural gas leases that have varying terms. The following table presents a summary of our acreage interests as of December 31, 2010:

	Developed Acreage		Undeveloped Acreage		Total Acreage	
	Gross	Net	Gross	Net	Gross	Net
State						
Alabama			27,298	22,747	27,298	22,747
Arkansas			1,109	560	1,109	560
Indiana			3,543	3,260	3,543	3,260
Louisiana	131,903	110,540	219,093	192,594	350,996	303,134
Oklahoma	40	20	97,064	52,679	97,104	52,699

Texas	84,261	57,662	542,414	331,801	626,675	389,463
Total Acreage	216,204	168,222	890,521	603,641	1,106,725	771,863

The table below reflects our net undeveloped and mineral acreage as of December 31, 2010 that will expire each year if we do not establish production in paying quantities on the units in which such

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acreage is included or do not pay (or do not have the contractual right to pay) delay rentals or other extensions to maintain the lease.

Year	Percentage Expiration
2011	44%
2012	33%
2013	16%
2014	3%
2015	3%
2016 & beyond	1%
	100%

At December 31, 2010, we had estimated proved reserves of approximately 3.4 trillion cubic feet of natural gas equivalent (Tcfe) comprised of 3,110 Bcf of natural gas, 27 MMBbls of natural gas liquids, and 20 MMBbls of oil. The following table sets forth, at December 31, 2010, these reserves:

	Proved Developed	Proved Undeveloped	Total Proved
Natural Gas (Bcf)	1,118.7	1,991.4	3,110.1
Oil (MMBbls)	5.7	14.1	19.8
Natural Gas Liquids (MMBbls)	5.2	21.9	27.1
Equivalent (Bcfe)	1,184.2	2,207.4	3,391.6

(1) *Oil and natural gas liquids are converted to equivalent gas reserves using a 6:1 equivalent ratio.*

At December 31, 2010, our estimated proved undeveloped (PUD) reserves were approximately 2,207 Bcfe, a 362 Bcfe net increase over the previous year's estimate of 1,845 Bcfe. The net increase is comprised of additions of 1,185 Bcfe, primarily attributable to drilling in the Haynesville and Eagle Ford Shales. The increase was partially offset by a reduction of approximately 823 Bcfe, which primarily relates to PUD reserves estimated as of December 31, 2009 that are currently scheduled for development at least five years from December 31, 2010 due to changes in the development timing of new and existing PUD reserves, and to the sale of certain non-core properties. During 2010, the majority of our total drilling and completion capital was allocated to drilling undeveloped leases in the Haynesville Shale to hold acreage. As of December 31, 2010, all of our PUD reserves included in the reserve report are less than five years in age and over 97% are less than three years in age. The following table summarizes the amount of PUD reserves that have been developed in each of the last three years using the amount of PUD reserves that we reported in the prior year:

	2010	2009	2008
PUD reserves at beginning of year (Bcfe)	1,845.0	625.8	454.8
PUD reserves developed (Bcfe)	109.2	22.0	71.3
% PUD reserves developed	6%	4%	16%

The estimates of quantities of proved reserves above were made in accordance with the definitions contained in SEC Release No. 33-8995, *Modernization of Oil and Gas Reporting*. For additional information on our oil and natural gas reserves, see Item 8. *Consolidated Financial Statements and Supplementary Data "Supplementary Oil and Gas Information (Unaudited)."*

We account for our oil and natural gas producing activities using the full cost method of accounting in accordance with SEC regulations. Accordingly, all costs incurred in the acquisition, exploration, and development of proved oil and natural gas properties, including the costs of

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abandoned properties, dry holes, geophysical costs, and annual lease rentals are capitalized. All general and administrative corporate costs unrelated to drilling activities are expensed as incurred. Sales or other dispositions of oil and natural gas properties are accounted for as adjustments to capitalized costs, with no gain or loss recorded unless the ratio of cost to proved reserves would significantly change. Depletion of evaluated oil and natural gas properties is computed on the units of production method based on proved reserves. The net capitalized costs of evaluated oil and natural gas properties are subject to a quarterly full cost ceiling test. At December 31, 2010 the ceiling test value of our reserves was calculated based on the first day average of the 12-months ended December 31, 2010 of the WTI spot price of $79.43 per barrel, adjusted by lease or field for quality, transportation fees, and regional price differentials, and the first day average of the 12-months ended December 31, 2010 of the Henry Hub price of $4.38 per Mmbtu, adjusted by lease or field for energy content, transportation fees, and regional price differentials. Using these prices, our net book value of oil and natural gas properties at December 31, 2010, did not exceed the ceiling amount. We recorded a full cost ceiling test impairment before income taxes of approximately $1.7 billion and $1.0 billion at March 31, 2009 and December 31, 2008, respectively, at which time the WTI posted price was $49.66 and $41.00 per barrel for oil, respectively, and the Henry Hub spot market price was $3.63 and $5.71 per Mmbtu for natural gas, respectively. At December 31, 2009, our 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 Henry Hub price of $3.87 per Mmbtu in accordance with SEC Release No. 33-8995, *Modernization of Oil and Gas Reporting*. As a result, we recorded a full cost ceiling test impairment before income taxes of approximately $106 million and $65 million after taxes.

Capitalized costs of our evaluated and unevaluated properties at December 31, 2010, 2009 and 2008 are summarized as follows:

	December 31,		
	2010	**2009**	**2008**
		(In thousands)	
Oil and natural gas properties (full cost method):			
Evaluated	$ 7,520,446	$ 5,984,765	$ 4,894,357
Unevaluated	2,387,037	2,512,453	2,287,968
Gross oil and natural gas properties	9,907,483	8,497,218	7,182,325
Less accumulated depletion	(4,774,579)	(4,329,485)	(2,111,038)
Net oil and natural gas properties	$ 5,132,904	$ 4,167,733	$ 5,071,287

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The following table summarizes our oil, natural gas and natural gas liquids production volumes, average sales price per unit and average costs per unit. In addition, this table summarizes our production for each field that contains 15% or more of our total proved reserves:

	Years Ended December 31,		
	2010	**2009**	**2008**
Production:			
Natural gas Mmcf			
Haynesville Shale	153,813	77,117	6,243
Eagle Ford Shale	15,047	6,688	123
Elm Grove / Caspiana	23,324	34,254	42,599
Other	42,354	54,237	51,178
Total	234,538	172,296	100,143
Oil MBbl			
Haynesville Shale			
Eagle Ford Shale	893	124	4
Elm Grove / Caspiana	83	133	151
Other	292	1,263	1,399
Total	1,268	1,520	1,554
Natural gas liquids MBbl			
Haynesville Shale			
Eagle Ford Shale	660		
Elm Grove / Caspiana			
Other	21	290	355
Total	681	290	355
Production:			
Natural gas equivalent Mmcfe[(1)]	246,232	183,156	111,597
Average daily production Mmcfe[(1)]	675	502	305
Average price per unit:[(2)]			
Natural gas price Mcf	$ 4.18	$ 3.69	$ 8.54
Crude oil price Bbl	76.98	56.15	95.16
Natural gas liquids price Bbl	38.03	28.20	56.63
Natural gas equivalent price Mcfe[(1)]	4.49	3.99	9.17
Average cost per Mcfe:			
Production:			
Lease operating	$ 0.26	$ 0.43	$ 0.47
Workover and other	0.07	0.02	0.05
Taxes other than income	0.04	0.31	0.42
Gathering, transportation and other:			
Oil and natural gas	0.61	0.38	0.39
Midstream	0.05	0.06	

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(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 or received on settled commodities derivative contracts as we did not elect to apply hedge accounting.*

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The 2010, 2009, and 2008 average oil, natural gas, and natural gas liquids sales prices above do not reflect the impact of cash paid on, or cash received from, settled derivative contracts as these amounts are reflected as "*Net gain on derivative contracts*" in the consolidated statements of operations, consistent with our decision not to elect hedge accounting. Including this impact 2010, 2009, and 2008 average crude oil sales prices were $76.90, $58.86, and $74.82 per Bbl and average natural gas sales prices were $5.22, $5.83, and $8.13 per Mcf. During 2010 we began hedging a portion of our natural gas liquids production for the first time. Including the impact of these hedges, our average natural gas liquids sales price was $37.10 per Bbl.

Competitive Conditions in the Business

The oil and natural gas industry is highly competitive and we compete with a substantial number of other companies that have greater financial and other resources. Many of these companies explore for, produce and market oil and natural gas, as well as carry on refining operations and market the resultant products on a worldwide basis. The primary areas in which we encounter substantial competition are in locating and acquiring desirable leasehold acreage for our drilling and development operations, locating and acquiring attractive producing oil and natural gas properties, obtaining sufficient availability of drilling and completion equipment and services, obtaining purchasers and transporters of the oil and natural gas we produce and hiring and retaining key employees. There is also competition between oil and natural gas producers and other industries producing energy and fuel. Furthermore, competitive conditions may be substantially affected by various forms of energy legislation and/or regulation considered from time to time by the government of the United States and the states in which our properties are located. It is not possible to predict the nature of any such legislation or regulation which may ultimately be adopted or its effects upon our future operations. Such laws and regulations may substantially increase the costs of exploring for, developing or producing oil and natural gas and may prevent or delay the commencement or continuation of a given operation.

Other Business Matters

Markets and Major Customers

In 2010, none of the individual purchasers of our production each accounted for in excess of 10% of our total sales. Three individual purchasers of our production each accounted for approximately 9% of our total sales, collectively representing approximately 27% of our total sales. In 2009, two individual purchasers of our production each accounted for in excess of 10% of our total sales, collectively representing 25% of our total sales. In 2008, two individual purchasers of our production each accounted for in excess of 10% of our total sales, collectively representing 30% of our total sales. We do not believe the loss of any one of our purchasers would materially affect our ability to sell the oil and natural gas we produce. We believe other purchasers are available in our areas of operations.

Seasonality of Business

Weather conditions affect the demand for, and prices of, natural gas and can also delay drilling activities, disrupting our overall business plans. Demand for natural gas is typically higher during the winter, resulting in higher natural gas prices for our natural gas production during our first and fourth fiscal quarters. Due to these seasonal fluctuations, our results of operations for individual quarterly periods may not be indicative of the results that we may realize on an annual basis.

Operational Risks

Oil and natural gas exploration and development involves a high degree of risk, which even a combination of experience, knowledge and careful evaluation may not be able to overcome. There is no assurance that we will discover or acquire additional oil and natural gas in commercial quantities. Oil and natural gas operations also involve the risk that well fires, blowouts, equipment failure, human error and other events may cause accidental leakage of toxic or hazardous materials, such as petroleum liquids or drilling fluids into the environment, or cause significant injury to persons or property. In such event, substantial liabilities to third parties or governmental entities may be incurred, the satisfaction of which could substantially reduce available cash and possibly result in loss of oil and natural gas properties. Such hazards may also cause damage to or destruction of wells, producing formations, production facilities and pipeline or other processing facilities.

As is common in the oil and natural gas industry, we will not insure fully against all risks associated with our business either because such insurance is not available or because we believe the premium costs are prohibitive. A loss not fully covered by insurance could have a materially adverse effect on our operating results, financial position or cash flows. For further discussion on risks see Item 1A. *Risk Factors*.

Regulations

All of the jurisdictions in which we own or operate producing oil and natural gas properties have statutory provisions regulating the exploration for and production of oil and natural gas, including provisions related to permits for the drilling of wells, bonding requirements to drill or operate wells, the location of wells, the method of drilling and casing wells, the surface use and restoration of properties upon which wells are drilled, sourcing and disposal of water used in the drilling and completion process, and the plugging and abandonment of wells. Our operations are also subject to various conservation laws and regulations. These include the regulation of the size of drilling and spacing units or proration units, the number of wells which may be drilled in an area, and the unitization or pooling of oil and natural gas properties, as well as regulations that generally prohibit the venting or flaring of natural gas, and impose certain requirements regarding the establishment of maximum allowable rates of production from fields and individual wells. The effect of these regulations is to limit the amount of oil and natural gas that we can produce from our wells and to limit the number of wells or the locations at which we can drill, although we can apply for exceptions to such regulations or to have reductions in well spacing. Failure to comply with applicable laws and regulations can result in substantial penalties. The regulatory burden on the industry increases the cost of doing business and affects profitability. Moreover, each state generally imposes a production or severance tax with respect to the production and sale of oil, natural gas and natural gas liquids within its jurisdiction.

Environmental Regulations

Our operations are subject to stringent federal, state and local laws regulating the discharge of materials into the environment or otherwise relating to health and safety or the protection of the environment. Numerous governmental agencies, such as the United States Environmental Protection Agency, commonly referred to as the EPA, issue regulations to implement and enforce these laws, which often require difficult and costly compliance measures. Failure to comply with these laws and regulations may result in the assessment of substantial administrative, civil and criminal penalties, as well as the issuance of injunctions limiting or prohibiting our activities. In addition, some laws and regulations relating to protection of the environment may, in certain circumstances, impose strict liability for environmental contamination, which could result in liability for environmental damages and cleanup costs without regard to negligence or fault on our part.

Environmental regulatory programs typically regulate the permitting, construction and operations of a facility. Many factors, including public perception, can materially impact the ability to secure an environmental construction or operation permit. Once operational, enforcement measures can include significant civil penalties for regulatory violations regardless of intent. Under appropriate circumstances, an administrative agency can issue a cease and desist order to terminate operations. New programs and changes in existing programs are anticipated, some of which include natural occurring radioactive materials, oil and natural gas exploration and production, waste management, and underground injection of waste material. Environmental laws and regulations have been subject to frequent changes over the years, and the imposition of more stringent requirements could have a material adverse effect on our financial condition and results of operations.

Comprehensive Environmental Response, Compensation and Liability Act and Hazardous Substances

The federal Comprehensive Environmental Response, Compensation and Liability Act, referred to as CERCLA or the Superfund law, and comparable state laws impose liability, without regard to fault, on certain classes of persons that are considered to be responsible for the release of a hazardous substance into the environment. These persons include the current or former owner or operator of the disposal site or sites where the release occurred and companies that disposed or arranged for the disposal of hazardous substances that have been released at the site. Under CERCLA, these persons may be subject to joint and several liability for the costs of investigating and cleaning up hazardous substances that have been released into the environment, for damages to natural resources and for the costs of some health studies. In addition, companies that incur liability frequently confront additional claims because it is not uncommon for neighboring landowners and other third parties to file claims for personal injury and property damage allegedly caused by hazardous substances or other pollutants released into the environment.

The Solid Waste Disposal Act and Waste Management

The federal Solid Waste Disposal Act, as amended by the Resource Conservation and Recovery Act of 1976, referred to as RCRA, generally does not regulate most wastes generated by the exploration and production of oil and natural gas because that act specifically excludes drilling fluids, produced waters and other wastes associated with the exploration, development or production of oil and natural gas from regulation as hazardous wastes. However, these wastes may be regulated by the EPA or state agencies as non-hazardous wastes as long as these wastes are not commingled with regulated hazardous wastes. Moreover, in the ordinary course of our operations, wastes generated in connection with our exploration and production activities may be regulated as hazardous waste under RCRA or hazardous substances under CERCLA. From time to time, releases of materials or wastes have occurred at locations we own or at which we have operations. These properties and the materials or wastes released thereon may be subject to CERCLA, RCRA and analogous state laws. Under these laws, we have been and may be required to remove or remediate these materials or wastes. At this time, with respect to any properties where materials or wastes may have been released, but of which we have not been made aware, it is not possible to estimate the potential costs that may arise from unknown, latent liability risks.

The Clean Water Act, wastewater and storm water discharges

Our operations are also subject to the federal Clean Water Act and analogous state laws. Under the Clean Water Act, the EPA has adopted regulations concerning discharges of storm water runoff. This program requires covered facilities to obtain individual permits, or seek coverage under a general permit. Some of our properties may require permits for discharges of storm water runoff and, as part of our overall evaluation of our current operations, we will apply for storm water discharge permit coverage and updating storm water discharge management practices at some of our facilities. We believe that we will be able to obtain, or be included under, these permits, where necessary, and make minor modifications to existing facilities and operations that would not have a material effect on us. The Clean Water Act and similar state acts regulate other discharges of wastewater, oil, and other pollutants to surface water bodies, such as lakes, rivers, wetlands, and streams. Failure to obtain permits for such discharges could result in civil and criminal penalties, orders to cease such discharges, and costs to remediate and pay natural resources damages. These laws also require the preparation and implementation of Spill Prevention, Control, and Countermeasure Plans in connection with on-site storage of significant quantities of oil.

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The Safe Drinking Water Act, groundwater protection, and the Underground Injection Control Program

The federal Safe Drinking Water Act (SWDA) and the Underground Injection Control (UIC) program promulgated under the SWDA and state programs regulate the drilling and operation of salt water disposal wells. EPA directly administers the UIC program in some states and in others it is delegated to the state for administering. Permits must be obtained before drilling salt water disposal permits, and casing integrity monitoring must be conducted periodically to ensure the casing is not leaking saltwater to groundwater. Contamination of groundwater by oil and natural gas drilling, production, and related operations may result in fines, penalties, and remediation costs, among other sanctions and liabilities under the SWDA and state laws. In addition, third party claims may be filed by landowners and other parties claiming damages for alternative water supplies, property damages, and bodily injury. 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. Certain states have adopted and are considering laws that require the disclosure of the chemical constituents in hydraulic fracturing fluids. In addition, in 2010, the EPA announced that it would be conducting a study on the environmental effects of hydraulic fracturing. The study is expected to be completed in 2012. Additional disclosure requirements could result in increased regulation, operational delays, and increased operating costs that could make it more difficult to perform hydraulic fracturing.

The Clean Air Act

The federal Clean Air Act and comparable state laws regulate emissions of various air pollutants through air emissions permitting programs and the imposition of other requirements. In addition, the EPA has developed and continues to develop stringent regulations governing emissions of toxic air pollutants at specified sources. Federal and state regulatory agencies can impose administrative, civil and criminal penalties for non-compliance with air permits or other requirements of the federal Clean Air Act and associated state laws and regulations. Our operations, or the operations of service companies engaged by us, may in certain circumstances and locations be subject to permits and restrictions under these statutes for emissions of air pollutants. In addition, the EPA has indicated that in 2011 it may revise its national emissions standards for hazardous air pollutants for crude oil and natural gas production and gas transmission and storage, as well as its new source performance standards for oil and gas production.

Climate change legislation and greenhouse gas regulation

Studies over recent years have indicated that emissions of certain gases may be contributing to warming of the Earth's atmosphere. In response to these studies, many nations have agreed to limit emissions of "greenhouse gases" or "GHGs" pursuant to the United Nations Framework Convention on Climate Change, and the "Kyoto Protocol." Methane, a primary component of natural gas, and carbon dioxide, a byproduct of the burning of oil, natural gas, and refined petroleum products, are considered "greenhouse gases" regulated by the Kyoto Protocol. Although the United States is not participating in the Kyoto Protocol, several states have adopted legislation and regulations to reduce emissions of greenhouse gases. Restrictions on emissions of methane or carbon dioxide that may be imposed in various states could adversely affect our operations and demand for our products. Additionally, the United States Supreme Court has ruled, in *Massachusetts, et al. v. EPA*, that the EPA abused its discretion under the Clean Air Act by refusing to regulate carbon dioxide emissions from mobile sources. As a result of the Supreme Court decision and the change in presidential administrations, on December 7, 2009, the EPA issued a finding that serves as the foundation under the Clean Air Act to issue other rules that would result in federal greenhouse gas regulations and emissions limits under the Clean Air Act, even without Congressional action. As part of this array of new regulations, on September 22, 2009, the EPA also issued a GHG monitoring and reporting rule that requires certain parties, including participants in the oil and natural gas industry, to monitor and report their GHG emissions, including methane and carbon dioxide, to the EPA. The emissions will be

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published on a register to be made available on the Internet. These regulations may apply to our operations. The EPA has issued two other rules that would regulate GHGs, one of which regulates GHGs from stationary sources, and one which requires sources in the oil and natural gas exploration and production industry and the pipeline industry to report GHG emissions. The EPA's finding, the greenhouse gas reporting rules, and the rules to regulate the emissions of greenhouse gases may affect the outcome of other climate change lawsuits pending in United States federal courts in a manner unfavorable to our industry.

Two recent court decisions, one before the United States Second Circuit Court of Appeals and one before the United States Fifth Circuit Court of Appeals (The Fifth Circuit) have allowed cases to proceed. In the first case, *Connecticut v. American Electric Power*, the Second Circuit ruled that several states and other plaintiffs could continue a suit to impose GHG reductions on several utility defendants, concluding that a political question and standing objections of the defendants did not prohibit the suit from going forward. In December 2010, the United States Supreme Court granted American Electric Power's petition for certiorari, and the case will be heard in 2011.The Fifth Circuit, in *Comer v. Murphy Oil*, ruled that plaintiffs could similarly pursue a damage suit and the political question did not prohibit the suit. This case involves claims by plaintiffs who suffered damages from Hurricane Katrina that are seeking to recover damages from certain GHG emitters asserting their emissions contributed to their increased damages. Even if no new federal greenhouse gas regulations are enacted, more than one-third of the states have begun taking action on their own to control and/or reduce emissions of greenhouse gases. Several multi-state programs have been developed or are in the process of being developed: the Regional Greenhouse Gas Initiative involving 10 Northeastern states, the Western Climate Initiative involving seven western states, and the Midwestern Greenhouse Gas Reduction Accord involving seven states. The latter two programs have several other states acting as observers and they may join one of the programs at a later date. Any of the climate change regulatory and legislative initiatives described above could have a material adverse effect on our business, financial condition, and results of operations.

The National Environmental Policy Act

Oil and natural gas exploration and production activities on federal lands are subject to the National Environmental Policy Act, or NEPA. NEPA requires federal agencies, including the Department of the Interior, to evaluate major agency actions that have the potential to significantly impact the environment. In the course of such evaluations, an agency will prepare an Environmental Assessment that assesses the potential direct, indirect and cumulative impacts of a proposed project and, if necessary, will prepare a more detailed Environmental Impact Statement that may be made available for public review and comment. All of our current exploration and production activities, as well as proposed exploration and development plans, on federal lands require governmental permits that are subject to the requirements of NEPA. This process has the potential to delay the development of oil and natural gas projects.

Threatened and endangered species, migratory birds, and natural resources

Various state and federal statutes prohibit certain actions that adversely affect endangered or threatened species and their habitat, migratory birds, wetlands, and natural resources. These statutes include the Endangered Species Act, the Migratory Bird Treaty Act, the Clean Water Act and CERCLA. The United States Fish and Wildlife Service may designate critical habitat and suitable habitat areas that it believes are necessary for survival of threatened or endangered species. A critical habitat or suitable habitat designation could result in further material restrictions to federal land use and private land use and could delay or prohibit land access or development. Where takings of or harm to species or damages to wetlands, habitat, or natural resources occur or may occur, government entities or at times private parties may act to prevent oil and gas exploration activities or seek damages for harm to species, habitat, or natural resources resulting from drilling or construction or releases of oil, wastes, hazardous substances or other regulated materials, and may seek natural resources damages and in some cases, criminal penalties.

Hazard communications and community right to know

We are subject to federal and state hazard communications and community right to know statutes and regulations. These regulations govern record keeping and reporting of the use and release of hazardous substances, including, but not limited to, the federal Emergency Planning and Community Right-to- Know Act.

Occupational Safety and Health Act

We are subject to the requirements of the federal Occupational Safety and Health Act, commonly referred to as OSHA, and comparable state statutes that regulate the protection of the health and safety of workers. In addition, the OSHA hazard communication standard requires that information be maintained about hazardous materials used or produced in operations and that this information be provided to employees, state and local government authorities and the public.

Employees

As of December 31, 2010, we had 598 full-time employees. We hire independent contractors on an as needed basis. We have no collective bargaining agreements with our employees. We believe that our employee relationships are satisfactory.

Access to Company Reports

We file periodic reports, proxy statements and other information with the SEC in accordance with the requirements of the Securities Exchange Act of 1934, as amended. We make our Annual Reports on Form 10-K, Quarterly Reports on Form 10-Q, Current Reports on Form 8-K and Forms 3, 4 and 5 filed on behalf of directors and officers, and any amendments to such reports available free of charge through our corporate website at *www.petrohawk.com* as soon as reasonably practicable after such reports are filed with, or furnished to, the SEC. In addition, our corporate governance guidelines, code of conduct, code of ethics for our chief executive officer (CEO) and senior financial officers, audit committee charter, compensation committee charter and nominating and corporate governance committee charter are available on our website under the heading "Company Profile Corporate Governance". Within the time period required by the SEC and the New York Stock Exchange (NYSE), as applicable, we will post on our website any modifications to the code of conduct and the code of ethics for our Chief Executive Officer and senior financial officers and any waivers applicable to senior officers as defined in the applicable code, as required by the Sarbanes-Oxley Act of 2002. You may also read and copy any document we file with the SEC at the SEC's Public Reference Room at 100 F Street, N.E., Washington, D.C. 20549. You may obtain information on the operation of the Public Reference Room by calling the SEC at 1-800-SEC-0330. In addition, our reports, proxy and information statements, and our other filings are also available to the public over the internet at the SEC's website at *www.sec.gov*. Unless specifically incorporated by reference in this Annual Report on Form 10-K, information that you may find on our website is not part of this report.

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Executive Officers

The following table sets forth the names and ages of all of our corporate officers, the positions and offices with us held by such persons, the terms of their office and the length of their continuous service as a corporate officer:

Name	Corporate Officer Since	Age	Position
Floyd C. Wilson	May 2004	63	Chairman of the Board and Chief Executive Officer
Richard K. Stoneburner	May 2004	57	President and Chief Operating Officer
Mark J. Mize	July 2005	39	Executive Vice President Chief Financial Officer and Treasurer
Larry L. Helm	July 2004	63	Executive Vice President Finance and Administration
Stephen W. Herod	May 2004	51	Executive Vice President Corporate Development and Assistant Secretary
David S. Elkouri	August 2007	57	Executive Vice President General Counsel and Secretary
H. Weldon Holcombe	March 2007	58	Executive Vice President Mid-Continent Region
Charles W. Latch	November 2007	66	Senior Vice President Western Region
Tina S. Obut	March 2007	45	Senior Vice President Corporate Reserves
Ellen R. DeSanctis	September 2010	54	Senior Vice President Corporate Communications
C. Byron Charboneau	March 2008	34	Vice President Chief Accounting Officer and Controller
Joan W. Dunlap	July 2007	36	Vice President Investor Relations
Charles E. Cusack III	May 2008	52	Vice President Exploration

Our executive officers are appointed to serve until the meeting of the board of directors following the next annual meeting of stockholders and until their successors have been elected and qualified.

Floyd C. Wilson has served as our Chairman of the Board and Chief Executive Officer since May 25, 2004. Mr. Wilson also served as our President from May 25, 2004 until September 8, 2009. Prior to May 25, 2004, he was President and Chief Executive Officer of PHAWK, LLC which he founded in June 2003. Mr. Wilson was the Chairman and Chief Executive Officer of 3TEC Energy Corporation from August 1999 until its merger with Plains Exploration & Production Company in June 2003. Mr. Wilson founded W/E Energy Company L.L.C., formerly known as 3TEC Energy Company L.L.C. in 1998 and served as its President until August 1999. Mr. Wilson began his career in the energy business in Houston, Texas in 1970 as a completion engineer. He moved to Wichita, Kansas in 1976 to start an oil and gas operating company, one of several private energy ventures which preceded the formation of Hugoton Energy Corporation in 1987, where he served as Chairman, President and Chief Executive Officer. In 1994, Hugoton completed an initial public offering and was merged into Chesapeake Energy Corporation in 1998.

Richard K. Stoneburner has served as our President and Chief Operating Officer since September 8, 2009. Mr. Stoneburner served as Executive Vice President Chief Operating Officer from September 13, 2007 until September 8, 2009 and had previously has served as Executive Vice President Exploration from August 1, 2005, until September 13, 2007. Mr. Stoneburner served as Vice President Exploration from May 25, 2004 until August 1, 2005. Prior to joining us, he was employed by PHAWK, LLC from its formation in June 2003 until May 2004. He joined 3TEC in August 1999 and was its Vice President Exploration from December 1999 until its merger with Plains Exploration & Production Company in June 2003. Mr. Stoneburner was employed by W/ E Energy

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Company as District Geologist from 1998 to 1999. Prior to joining 3TEC, Mr. Stoneburner worked as a geologist for Texas Oil & Gas, The Reach Group, Weber Energy Corporation, Hugoton and, independently through his own company, Stoneburner Exploration, Inc. Mr. Stoneburner has over 31 years of experience in the energy business.

Mark J. Mize has served as Executive Vice President Chief Financial Officer and Treasurer since August 10, 2007. Mr. Mize was also appointed and has served as our Chief Ethics Officer and Insider Trading Compliance Officer through June 17, 2009. He served as Vice President, Chief Accounting Officer and Controller from July 2005 until August 10, 2007. Mr. Mize joined us on November 29, 2004 as Controller. Prior to joining us, he was the Manager of Financial Reporting of Cabot Oil & Gas Corporation, a public oil and gas exploration company, from January 2003 to November 2004. Prior to his employment at Cabot Oil & Gas Corporation, he was an Audit Manager with PricewaterhouseCoopers LLP from 1996 to 2002. Mr. Mize is a Certified Public Accountant.

Larry L. Helm has served as Executive Vice President Finance and Administration since August 10, 2007. Mr. Helm served as Vice President Chief Administrative Officer from July 15, 2004 until August 1, 2005, and as Executive Vice President Chief Administrative Officer from August 1, 2005 until August 9, 2007. Prior to serving as an executive officer, Mr. Helm served on our board of directors for approximately two months. Mr. Helm was employed with Bank One Corporation from December 1989 through December 2003. Most recently Mr. Helm served as Executive Vice President of Middle Market Banking from October 2001 to December 2003. From April 1998 to August 1999, he served as Executive Vice President of the Energy and Utilities Banking Group. Prior to joining Bank One, he worked for 16 years in the banking industry primarily serving the oil and gas sector. He served as director of 3TEC Energy Corporation from 2000 to June 2003.

Stephen W. Herod has served as Executive Vice President Corporate Development and Assistant Secretary since August 1, 2005. Mr. Herod served as Vice President Corporate Development from May 25, 2004 until August 1, 2005. Prior to joining us, he was employed by PHAWK, LLC from its formation in June 2003 until May 2004. He served as Executive Vice President Corporate Development for 3TEC Energy Corporation from December 1999 until its merger with Plains Exploration & Production Company in June 2003 and as Assistant Secretary from May 2001 until June 2003. Mr. Herod served as a director of 3TEC from July 1997 until January 2002. Mr. Herod served as the Treasurer of 3TEC from 1999 until 2001. From July 1997 to December 1999, Mr. Herod was Vice President Corporate Development of 3TEC. Mr. Herod served as President and a director of Shore Oil Company from April 1992 until the merger of Shore with 3TEC's predecessor in June 1997. He joined Shore's predecessor as Controller in February 1991. Mr. Herod was employed by Conquest Exploration Company from 1984 until 1991 in various financial management positions, including Operations Accounting Manager. From 1981 to 1984, Superior Oil Company employed Mr. Herod as a financial analyst.

David S. Elkouri has served as Executive Vice President General Counsel and Secretary of the Company since August 1, 2007. Mr. Elkouri has also served as Chief Ethics Officer and Insider Trading Compliance Officer since June 18, 2009. Mr. Elkouri has served as lead outside counsel for Petrohawk since 2004 and has been actively involved with the Company's growth since that time. Prior to that time he served as lead outside counsel for 3TEC Energy Corporation from its inception in 1999 until it was acquired in 2003 and for Hugoton Energy Corporation from its inception in 1994 until it was acquired in 1998. Mr. Elkouri's practice has focused on tax, corporate and securities law with an emphasis on the oil and gas industry. Mr. Elkouri is a graduate of the University of Kansas School of Law where he served as a Research Editor of the Kansas Law Review.

H. Weldon Holcombe joined the Company on July 12, 2006, effective upon the merger of KCS Energy, Inc. (KCS) with and into the Company and served as Senior Vice President Mid-Continent Region from March 1, 2007 until October 1, 2007 when he became Executive Vice President Mid-Continent Region. After the merger of KCS and Petrohawk, Mr. Holcombe became responsible

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for all of the merged company's operations in the Mid-Continent Region including our interests in the Elm Grove and Terryville fields among others throughout the Mid-Continent Region. With the Company's acquisition of Fayetteville Shale acreage in Arkansas and Haynesville Shale acreage in North Louisiana and East Texas, Mr. Holcombe became responsible for the growth and development of these key assets. Prior to the merger of KCS and Petrohawk, Mr. Holcombe served as Senior Vice President of KCS responsible for operations and engineering. Prior to joining KCS in 1996, he spent many years with Exxon in project and management positions associated with sour gas treatment, drilling, completions and reservoir management. Mr. Holcombe holds a degree in engineering from Auburn University.

Charles W. Latch has served as the Company's Senior Vice President Western Region since November 2007. From July 2006 through October 2007, Mr. Latch served as the Company's Vice President of Operations. From 2004 until joining the Company in July 2006, Mr. Latch was employed by KCS Resources, serving as Vice President of Operations since November 2004. Mr. Latch was Senior Vice President of Technical Services with El Paso Production Company from November 2002 until joining KCS Resources.

Tina S. Obut has served as Senior Vice President Corporate Reserves since May 15, 2008. Ms. Obut served as Vice President Corporate Reserves from March 2007 to May 15, 2008. Ms. Obut initially joined the Company in April 2006 as Manager of Corporate Reserves. Prior to joining us, Ms. Obut was employed by El Paso Production Company as Manager of Reservoir Engineering Evaluations from July 2004 until April 2006. From 2001 to 2004, Ms. Obut was Planning and Asset Manager at Mission Resources. From 1992 to 2001, Ms. Obut was a Vice President with Ryder Scott Company, and from 1989 to 1992, she worked as a reservoir engineer with Chevron. Ms. Obut is a Registered Petroleum Engineer.

Ellen R. DeSanctis has served as the Company's Senior Vice President Corporate Communications since September 2010. Prior to joining Petrohawk, Ellen was employed as Executive Vice President, Strategy and Development for Rosetta Resources since 2008. From 2006 to 2008, Ms. DeSanctis ran E. R. DeSanctis Consulting Services, which specialized in strategy development, and investor relations for exploration and production companies. From 2000 to 2006, she served as Vice President-Corporate Communications and Strategic Planning for Burlington Resources. She spent several years with Vastar Resources in various capacities and spent eight years in the Atlantic Richfield organization. She began her career at Shell Oil Company. She holds a bachelor's degree in geological & geophysical sciences from Princeton University and an M.B.A. from the University of California, Los Angeles.

C. Byron Charboneau has served as the Company's Vice President Chief Accounting Officer and Controller since March 2008. From August 2007 through February 2008, Mr. Charboneau served as the Financial Controller and from January 2005 through July 2007, Mr. Charboneau served as the Company's Director of Compliance and Accounting Research. From 1999 until joining the Company in January 2005, Mr. Charboneau was employed in the audit practice of PricewaterhouseCoopers, most recently as an audit manager with the Energy, Utilities and Mining Industry group. Mr. Charboneau is a Certified Public Accountant in New York.

Joan W. Dunlap has served as Vice President Investor Relations since July 2007. From August 2004 until 2006, Ms. Dunlap served as the Company's Assistant Treasurer. Prior to joining Petrohawk, she was employed as an investment banking associate with JPMorgan Chase, accredited with Series 7 and Series 63, and as a financial analyst and research assistant for the Federal Reserve Bank. Ms. Dunlap holds a bachelor's degree in economics from Tulane University and an M.B.A. from Rice University.

Charles E. Cusack III has served as Vice President Exploration since May 2008. Mr. Cusack is responsible for the exploration and land leasing efforts of the company. He was most recently Exploration Manager for the Gulf Coast Division prior to its sale in 2007. Mr. Cusack has 29 years of industry experience having held various positions with 3TEC Energy, Cockrell Oil, Amerada Hess, Chevron, Tenneco Oil, and Gulf Oil. He holds an engineering geology degree from Texas A&M University.

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ITEM 1A. RISK FACTORS

We have substantial indebtedness and may incur substantially more debt. Higher levels of indebtedness make us more vulnerable to economic downturns and adverse developments in our business.

We have incurred substantial debt amounting to approximately $2.6 billion as of December 31, 2010. As a result of our indebtedness, we will need to use a portion of our cash flow to pay interest, which will reduce the amount we will have available to finance our operations and other business activities and could limit our flexibility in planning for or reacting to changes in our business and the industry in which we operate. Our indebtedness under our Senior Credit Agreement is at a variable interest rate, and so a rise in interest rates will generate greater interest expense to the extent we do not have applicable interest rate fluctuation hedges. The amount of our debt may also cause us to be more vulnerable to economic downturns and adverse developments in our business.

We may incur substantially more debt in the future. The indentures governing our outstanding senior notes contain restrictions on our incurrence of additional indebtedness. These restrictions, however, are subject to a number of qualifications and exceptions, and under certain circumstances, we could incur substantial additional indebtedness in compliance with these restrictions. Moreover, these restrictions do not prevent us from incurring obligations that do not constitute indebtedness under the indentures. At December 31, 2010, our Senior Credit Agreement was a $2.0 billion facility with a borrowing base of $1.65 billion, $1.55 billion of which relates to our oil and natural gas properties and up to $100 million of which relates to our midstream assets (which was limited to approximately $38 million based on the EBITDA limitation at December 31, 2010). As of December 31, 2010, we had $146 million of debt outstanding under this facility and $1.4 billion of additional borrowing capacity available.

Our ability to meet our debt obligations and other expenses will depend on our future performance, which will be affected by financial, business, economic, regulatory and other factors, many of which we are unable to control. If our cash flow is not sufficient to service our debt, we may be required to refinance debt, sell assets or sell additional shares of common stock on terms that we may not find attractive if it may be done at all. Further, our failure to comply with the financial and other restrictive covenants relating to our indebtedness could result in a default under that indebtedness, which could adversely affect our business, financial condition and results of operations.

We may not be able to drill wells on a substantial portion of our acreage.

We may not be able to drill on a substantial portion of our acreage for various reasons. We may not generate or be able to raise sufficient capital to do so. Future deterioration in commodities pricing may also make drilling some acreage uneconomic. Our actual drilling activities and future drilling budget will depend on drilling results, oil and natural gas prices, the availability and cost of capital, drilling and production costs, availability of drilling services and equipment, lease expirations, gathering system and pipeline transportation constraints, regulatory approvals and other factors. In addition, any drilling activities we are able to conduct may not be successful or add additional proved reserves to our overall proved reserves, which could have a material adverse effect on our future business, financial condition and results of operations.

Part of our strategy involves drilling in shale formations, some of which are new and emerging, using horizontal drilling and completion techniques. The results of our drilling program using these techniques may be subject to more uncertainties than conventional drilling programs, especially in areas that are new and emerging. These uncertainties could result in an inability to meet our expectations for reserves and production.

The results of our drilling in new or emerging formations, such as the Lower Bossier Shale and certain areas of the Eagle Ford Shale, are more uncertain initially than drilling results in areas that are more developed and have a longer history of established production. Newer or emerging formations and areas have limited or no production history and consequently we are less able to predict future drilling results in these areas. In addition, the use of horizontal drilling and completion techniques used in all of our shale formations involve certain risks and complexities that do not exist in conventional wells. Our experience, as well as that of the industry as a whole, is significant but still growing in this area. The ultimate success of these drilling and completion strategies and techniques will be better evaluated over time as more wells are drilled and production profiles are better established.

If our drilling results are less than anticipated our investment in these areas may not be as attractive as we anticipate and we could incur material write downs of unevaluated properties and the value of our undeveloped acreage could decline in the future.

Certain of our undeveloped leasehold acreage is subject to leases that will expire over the next several years unless production is established on units containing the acreage.

As of December 31, 2010, we own leasehold interests in approximately 363,000 net acres in areas we believe are prospective for the Haynesville Shale, approximately 390,000 net acres in areas we believe are prospective for the Eagle Ford Shale and 150,000 net acres in areas we believe are prospective for the Lower Bossier Shale. A large portion of our acreage is not currently held by production. Unless production in paying quantities is established on units containing these leases during their terms, these leases will expire. If our leases expire, we will lose our right to develop the related properties.

Our drilling plans for these areas are subject to change based upon various factors, many of which are beyond our control, including drilling results, oil and natural gas prices, the availability and cost of capital, drilling and production costs, availability of drilling services and equipment, gathering system and pipeline transportation constraints, and regulatory approvals. Further, some of our acreage is located in sections where we do not hold the majority of the acreage and therefore it is likely that we will not be named operator of these sections. As a non-operating leaseholder we have less control over the timing of drilling and there is therefore additional risk of expirations occurring in sections where we are not the operator.

Our ability to sell our production and/or receive market prices for our production may be adversely affected by transportation capacity constraints and interruptions.

If the amount of natural gas, condensate or oil being produced by us and others exceeds the capacity of the various transportation pipelines and gathering systems currently available in our operating areas, it will be necessary for new transportation pipelines and gathering systems to be built. Or, in the case of oil and condensate, it will be necessary for us to rely more heavily on trucks to transport our production, which is more expensive and less efficient than transportation via pipeline. Currently, we anticipate that additional pipeline capacity will be required in the Eagle Ford Shale to transport oil and condensate production, which increased substantially during 2010 and is expected to continue to increase. The construction of new pipelines and gathering systems is capital intensive and construction may be postponed, interrupted or cancelled in response to changing economic conditions and the availability and cost of capital. In addition, capital constraints could limit our ability to build gathering systems to transport our production to transportation pipelines. In such event, costs to transport our production may increase materially or we might have to shut in our wells awaiting a pipeline connection or capacity and/or sell our production at much lower prices than market or than we currently project, which would adversely affect our results of operations.

A portion of our production may also be interrupted, or shut in, from time to time for numerous other reasons, including as a result of weather conditions, accidents, loss of pipeline or gathering system access, field labor issues or strikes, or we might voluntarily curtail production in response to market conditions. If a substantial amount of our production is interrupted at the same time, it could adversely affect our cash flow.

We may have difficulty financing our planned capital expenditures which could adversely affect our growth.

We have experienced, and expect to continue to experience, substantial capital expenditure and working capital needs, primarily as a result of our drilling program, particularly in the Haynesville, Lower Bossier, and Eagle Ford Shales. We intend to continue to selectively increase our acreage position in the Haynesville, Lower Bossier, and Eagle Ford Shales, which would require capital in addition to the capital necessary to drill on our existing acreage. In addition, it is likely that we will acquire acreage in other areas that we believe are prospective for oil and natural gas production and expend capital to develop such acreage. We expect to use borrowings under our Senior Credit Agreement, proceeds from potential asset dispositions and proceeds from potential future capital markets transactions, if necessary, to fund capital expenditures that are in excess of our cash flow and cash on hand.

Our Senior Credit Agreement limits our borrowings to the lesser of the borrowing base and the total commitments. Our borrowing base related to our oil and natural gas properties is $1.55 billion as of December 31, 2010. Our borrowing base is determined semi-annually, and may also be redetermined periodically at the discretion of the banks. Lower oil and natural gas prices may result in a reduction in our borrowing base at the next redetermination. A reduction in our borrowing base could require us to repay any indebtedness in excess of the borrowing base. 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 under the most restrictive indenture. 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, increasing to $1 billion upon redemption of the 2012 Notes) and a percentage (the most restrictive indenture limit currently being 20%, but increasing to 30% upon the redemption of the 2012 Notes) of our adjusted consolidated net tangible assets (as defined in all of our indentures), which is determined using discounted future net revenues from proved oil and natural gas reserves as of the end of each year. Currently, we are permitted to incur additional indebtedness under these incurrence tests, but may be limited in the future. Lower oil and natural gas prices in the future could reduce our adjusted consolidated EBITDA, as well as our adjusted consolidated net tangible assets, and thus could reduce our ability to incur additional indebtedness.

Additionally, our ability to complete future equity offerings is limited by general market conditions. If we are not able to borrow sufficient amounts under our Senior Credit Agreement and/or are unable to raise sufficient capital to fund our capital expenditures, we may be required to curtail our drilling, development, land acquisition and other activities, which could result in a decrease in our production of oil and natural gas, forfeiture of leasehold interests if we are unable or unwilling to renew them, and could force us to sell some of our assets on an untimely or unfavorable basis, each of which could have a material adverse effect on our results and future operations.

Oil and natural gas prices are volatile, and low prices could have a material adverse impact on our business.

Our revenues, profitability and future growth and the carrying value of our properties depend substantially on prevailing oil and natural gas prices. Prices also affect the amount of cash flow available for capital expenditures and our ability to borrow and raise additional capital. The amount we will be able to borrow under our Senior Credit Agreement will be subject to periodic redetermination

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based in part on current oil and natural gas prices and on changing expectations of future prices. Lower prices may also reduce the amount of oil and natural gas that we can economically produce and have an adverse effect on the value of our properties.

Historically, the markets for oil and natural gas have been volatile, and they are likely to continue to be volatile in the future. Among the factors that can cause volatility are:

- the domestic and foreign supply of oil and natural gas;
- the ability of members of the Organization of Petroleum Exporting Countries and other producing countries to agree upon and maintain oil prices and production levels;
- social unrest and political instability, particularly in oil and natural gas producing regions, such as the Middle East, and armed conflict or terrorist attacks, whether or not in oil or natural gas producing regions;
- the level of consumer product demand;
- the growth of consumer product demand in emerging markets, such as China;
- labor unrest in oil and natural gas producing regions;
- weather conditions, including hurricanes and other natural occurrences that affect the supply and/or demand of oil and natural gas;
- the price and availability of alternative fuels;
- the price of foreign imports;
- worldwide economic conditions; and
- the availability of liquid natural gas imports.

These external factors and the volatile nature of the energy markets make it difficult to estimate future prices of oil and natural gas.

Unless we replace our reserves, our reserves and production will decline, which would adversely affect our financial condition, results of operations and cash flows.

Producing oil and natural gas reservoirs generally are characterized by declining production rates that vary depending upon reservoir characteristics and other factors. Decline rates are typically greatest early in the productive life of a well. For instance, we currently estimate that our Haynesville and Eagle Ford Shale operated wells on restricted choke will decline approximately 30-60% and 65-85%, respectively, during the first twelve months of production. Estimates of the decline rate of an oil or natural gas well are inherently imprecise, and are less precise with respect to new or emerging oil and natural gas formations with limited production histories than for more developed formations with established production histories. Our production levels and the reserves that we currently expect to recover from our wells will change if production from our existing wells declines in a different manner than we have estimated and can change under other circumstances. Thus, our future oil and natural gas reserves and production and, therefore, our cash flow and results of operations are highly dependent upon our success in efficiently developing and exploiting our current properties and economically finding or acquiring additional recoverable reserves. We may not be able to develop, find or acquire additional reserves to replace our current and future production at acceptable costs. If we are unable to replace our current and future production, our cash flows and the value of our reserves may decrease, adversely affecting our business, financial condition and results of operations.

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

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

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

At December 31, 2010, approximately 65% of our estimated reserves were classified as proved undeveloped. Recovery of proved undeveloped reserves requires significant capital expenditures and successful drilling operations. The reserve data assumes that we will make significant capital expenditures to develop our reserves. Although we have prepared estimates of these oil and natural gas reserves and the costs associated with development of these reserves in accordance with SEC regulations, actual capital expenditures will likely vary from estimated capital expenditures, development may not occur as scheduled and actual results may not be as estimated.

We depend substantially on the continued presence of key personnel for critical management decisions and industry contacts.

Our success depends upon the continued contributions of our executive officers and key employees, particularly with respect to providing the critical management decisions and contacts necessary to manage and maintain growth within a highly competitive industry. Competition for qualified personnel can be intense, particularly in the oil and natural gas industry, and there are a limited number of people with the requisite knowledge and experience. Under these conditions, we could be unable to attract and retain these personnel. The loss of the services of any of our executive officers or other key employees for any reason could have a material adverse effect on our business, operating results, financial condition and cash flows.

Our business is highly competitive.

The oil and natural gas industry is highly competitive in many respects, including identification of attractive oil and natural gas properties for acquisition, drilling and development, securing financing for such activities and obtaining the necessary equipment and personnel to conduct such operations and activities. In seeking suitable opportunities, we compete with a number of other companies, including large oil and natural gas companies and other independent operators with greater financial resources, larger numbers of personnel and facilities, and, in some cases, with more expertise. There can be no assurance that we will be able to compete effectively with these entities.

Our oil and natural gas activities are subject to various risks which are beyond our control.

Our operations are subject to many risks and hazards incident to exploring and drilling for, producing, transporting, marketing and selling oil and natural gas. Although we may take precautionary measures, many of these risks and hazards are beyond our control and unavoidable under the circumstances. Many of these risks or hazards could materially and adversely affect our revenues and expenses, the ability of certain of our wells to produce oil and natural gas in commercial quantities, the rate of production and the economics of the development of, and our investment in the prospects in which we have or will acquire an interest. Any of these risks and hazards could materially and adversely affect our financial condition, results of operations and cash flows. Such risks and hazards include:

- human error, accidents, labor force and other factors beyond our control that may cause personal injuries or death to persons and destruction or damage to equipment and facilities;
- blowouts, fires, hurricanes, pollution and equipment failures that may result in damage to or destruction of wells, producing formations, production facilities and equipment;
- unavailability of materials and equipment;
- engineering and construction delays;
- unanticipated transportation costs and delays;
- unfavorable weather conditions;
- hazards resulting from unusual or unexpected geological or environmental conditions;
- environmental regulations and requirements;
- accidental leakage of toxic or hazardous materials, such as petroleum liquids or drilling fluids, into the environment;
- hazards resulting from the presence of hydrogen sulfide (H_2S) or other contaminants in gas we produce;
- changes in laws and regulations, including laws and regulations applicable to oil and natural gas activities or markets for the oil and natural gas produced;
- fluctuations in supply and demand for oil and natural gas causing variations of the prices we receive for our oil and natural gas production; and
- the availability of alternative fuels and the price at which they become available.

As a result of these risks, expenditures, quantities and rates of production, revenues and operating costs may be materially adversely affected and may differ materially from those anticipated by us.

We are subject to complex federal, state, local and other laws and regulations that could adversely affect the cost, manner or feasibility of doing business.

Companies that explore for and develop, produce, sell and transport oil and natural gas in the United States are subject to extensive federal, state and local laws and regulations, including complex tax and environmental, health and safety laws and the corresponding regulations, and are required to obtain various permits and approvals from federal, state and local agencies. If these permits are not issued or unfavorable restrictions or conditions are imposed on our drilling activities, we may not be able to conduct our operations as planned. We may be required to make large expenditures to comply with governmental regulations. Matters subject to regulation include:

- water discharge and disposal permits for drilling operations;
- drilling bonds;
- drilling permits;
- reports concerning operations;
- air quality, noise levels and related permits;

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- spacing of wells;
- rights-of-way and easements;
- unitization and pooling of properties;
- pipeline construction;
- gathering, transportation and marketing of oil and natural gas;
- taxation; and
- waste transport and disposal permits and requirements.

Failure to comply with these laws may result in the suspension or termination of operations and subject us to liabilities under administrative, civil and criminal penalties. Compliance costs can be significant. Moreover, these laws or the enforcement thereof could change in ways that substantially increase the costs of doing business. Any such liabilities, penalties, suspensions, terminations or regulatory changes could materially and adversely affect our business, financial condition and results of operations. Under these laws and other environmental health and safety laws and regulations, we could be held liable for personal injuries, property damage (including site clean-up and restoration costs) and other damages. Failure to comply with these laws and regulations may also result in the suspension or termination of our operations and subject us to administrative, civil and criminal penalties, including the assessment of natural resource damages. Some laws and regulations may impose strict as well as joint and several liability for environmental contamination, which could subject us to liability for the conduct of others or for our own actions that were in compliance with all applicable laws at the time such actions were taken. Environmental and other governmental laws and regulations also increase the costs to plan, design, drill, install, operate and abandon oil and natural gas wells. Moreover, public interest in environmental protection has increased in recent years, and environmental organizations have opposed, with some success, certain drilling projects. Part of the regulatory environment in which we operate includes, in some cases, federal requirements for performing or preparing environmental assessments, environmental impact studies and/or plans of development before commencing exploration and production activities. In addition, our activities are subject to the regulation by oil and natural gas-producing states relating to conservation practices and protection of correlative rights. These regulations affect our operations and limit the quantity of oil and natural gas we may produce and sell. Delays in obtaining regulatory approvals or necessary permits, the failure to obtain a permit or the receipt of a permit with excessive conditions or costs could have a material adverse effect on our ability to explore on, develop or produce our properties. Additionally, the oil and natural gas regulatory environment could change in ways that might substantially increase the financial and managerial costs to comply with the requirements of these laws and regulations and, consequently, adversely affect our profitability.

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

Legislation was proposed in the last 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. If similar legislation is ultimately adopted, it 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.

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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 drinking water resources. Interim results of the study are expected in 2012, with final results expected in 2014. 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.

Possible regulation related to global warming and climate change could have an adverse effect on our operations and demand for oil and natural gas.

Studies over recent years have indicated that emissions of certain gases may be contributing to warming of the Earth's atmosphere. In response to these studies, governments have begun adopting domestic and international climate change regulations that requires reporting and reductions of the emission of greenhouse gases. Methane, a primary component of natural gas, and carbon dioxide, a byproduct of the burning of oil, natural gas and refined petroleum products, are considered greenhouse gases. Internationally, the United Nations Framework Convention on Climate Change, and the Kyoto Protocol address greenhouse gas emissions, and several counties including the European Union have established greenhouse gas regulatory systems. In the United States, at the state level, many states, either individually or through multi-state regional initiatives, have begun implementing legal measures to reduce emissions of greenhouse gases, primarily through the planned development of emission inventories or regional greenhouse gas cap and trade programs or have begun considering adopting greenhouse gas regulatory programs.

The EPA has issued greenhouse gas monitoring and reporting regulations that went into effect January 1, 2010, and require reporting by regulated facilities by March 2011 and annually thereafter. In November 2010, the EPA issued a final rule requiring companies to report certain greenhouse gas emissions from oil and natural gas facilities. Beyond measuring and reporting, the EPA issued an "Endangerment Finding" under section 202(a) of the Clean Air Act, concluding greenhouse gas pollution threatens the public health and welfare of current and future generations. The finding serves as a first step to issuing regulations that would require permits for and reductions in greenhouse gas emissions for certain facilities. EPA has proposed such greenhouse gas regulations and may issue final rules this year.

In the courts, several decisions have been issued that may increase the risk of claims being filed by governments and private parties against companies that have significant greenhouse gas emissions. Such cases may seek to challenge air emissions permits that greenhouse gas emitters apply for and seek to force emitters to reduce their emissions or seek damages for alleged climate change impacts to the environment, people, and property.

Any laws or regulations that may be adopted to restrict or reduce emissions of greenhouse gases could require us to incur increased operating and compliance costs, and could have an adverse effect on demand for the oil and natural gas that we produce.

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 SEC 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.

The proposed United States federal budget for fiscal year 2011 and other pending legislation contain certain provisions that, if passed as originally submitted, will have an adverse effect on our financial position, results of operations, and cash flows.

In February 2009, the Obama administration released its budget proposals for the fiscal year 2010, which included numerous proposed tax changes. In April 2009, legislation was introduced to further these objectives and in February 2010, the Obama administration released similar budget proposals for the fiscal year 2011. The proposed budget and legislation would repeal many tax incentives and deductions that are currently used by oil and gas companies in the United States and impose new taxes. Among others, the provisions include: elimination of the ability to fully deduct intangible drilling costs in the year incurred; repeal of the percentage depletion deduction for oil and gas properties; repeal of the manufacturing tax deduction for oil and gas companies; increase in the geological and geophysical amortization period for independent producers; and implementation of a fee on non-producing leases located on federal lands. Should some or all of these provisions become law, our taxes could increase, potentially significantly, after net operating losses are exhausted, which would have a negative impact on our results of operations and cash flows. This could also reduce our drilling activities. Although these proposals initially were made approximately one year ago, none have been voted on or become law. However, it is still the Obama administration's stated intention to enact these provisions. We do not know the ultimate impact these proposed changes may have on our business.

We cannot be certain that the insurance coverage maintained by us will be adequate to cover all losses that may be sustained in connection with all oil and natural gas activities.

We maintain general and excess liability policies, which we consider to be reasonable and consistent with industry standards. These policies generally cover:

- personal injury;
- bodily injury;

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- third party property damage;
- medical expenses;
- legal defense costs;
- pollution in some cases;
- well blowouts in some cases; and
- workers compensation.

As is common in the oil and natural gas industry, we will not insure fully against all risks associated with our business either because such insurance is not available or because we believe the premium costs are prohibitive. A loss not fully covered by insurance could have a materially adverse effect on our financial position, results of operations and cash flows. There can be no assurance that the insurance coverage that we maintain will be sufficient to cover every claim made against us in the future.

Title to the properties in which we have an interest may be impaired by title defects.

We generally obtain title opinions on significant properties that we drill or acquire. However, there is no assurance that we will not suffer a monetary loss from title defects or title failure. Additionally, undeveloped acreage has greater risk of title defects than developed acreage. Generally, under the terms of the operating agreements affecting our properties, any monetary loss is to be borne by all parties to any such agreement in proportion to their interests in such property. If there are any title defects or defects in assignment of leasehold rights in properties in which we hold an interest, we will suffer a financial loss.

Assets we acquire may prove to be worth less than we paid because of uncertainties in evaluating recoverable reserves and potential liabilities.

Our recent growth is due significantly to acquisitions of exploration and production companies, producing properties and undeveloped and unevaluated leaseholds. We expect acquisitions may also contribute to our future growth. Successful acquisitions require an assessment of a number of factors, including estimates of recoverable reserves, exploration potential, future oil and natural gas prices, operating and capital costs and potential environmental and other liabilities. Such assessments are inexact and their accuracy is inherently uncertain. In connection with our assessments, we perform a review of the acquired properties which we believe is generally consistent with industry practices. However, such a review will not reveal all existing or potential problems. In addition, our review may not permit us to become sufficiently familiar with the properties to fully assess their deficiencies and capabilities. We do not inspect every well. Even when we inspect a well, we do not always discover structural, subsurface and environmental problems that may exist or arise. We are generally not entitled to contractual indemnification for preclosing liabilities, including environmental liabilities. Normally, we acquire interests in properties on an "as is" basis with limited remedies for breaches of representations and warranties. As a result of these factors, we may not be able to acquire oil and natural gas properties that contain economically recoverable reserves or be able to complete such acquisitions on acceptable terms.

Our exploration and development drilling efforts and the operation of our wells may not be profitable or achieve our targeted returns.

We require significant amounts of undeveloped leasehold acreage to further our development efforts. Exploration, development, drilling and production activities are subject to many risks, including the risk that commercially productive reservoirs will not be discovered. We invest in property, including undeveloped leasehold acreage, which we believe will result in projects that will add value over time. However, we cannot guarantee that our leasehold acreage will be profitably developed, that new wells drilled by us will be productive or that we will recover all or any portion of our investment in such leasehold acreage or wells. Drilling for oil and natural gas may involve unprofitable efforts, not only from dry wells but also from wells that are productive but do not produce sufficient net reserves to return a profit after deducting operating and other costs. In addition, wells that are profitable may not achieve our targeted rate of return. Our ability to achieve our target results are dependent upon the current and future market prices for oil and natural gas, costs associated with producing oil and natural gas and our ability to add reserves at an acceptable cost.

In addition, we may not be successful in controlling our drilling and production costs to improve our overall return. The cost of drilling, completing and operating a well is often uncertain and cost factors can adversely affect the economics of a project. We cannot predict the cost of drilling and completing a well, and we may be forced to limit, delay or cancel drilling operations as a result of a variety of factors, including:

- unexpected drilling conditions;
- pressure or irregularities in formations;
- equipment failures or accidents and shortages or delays in the availability of drilling and completion equipment and services;
- adverse weather conditions, including hurricanes; and
- compliance with governmental requirements.

The unavailability or high cost of drilling rigs, pressure pumping equipment and crews, other equipment, supplies, water, personnel and oil field services could adversely affect our ability to execute our exploration and development plans on a timely basis and within our budget.

Our industry is cyclical and, from time to time, there is a shortage of drilling rigs, equipment, supplies, water or qualified personnel. There is currently a shortage of pressure pumping equipment and crews in all of our areas of operation. During these periods, the costs and delivery times of rigs, equipment and supplies are substantially greater. In addition, the demand for, and wage rates of, qualified drilling rig crews rise as the number of active rigs in service increases. Increasing levels of exploration and production may increase the demand for oilfield services and equipment, and the costs of these services and equipment may increase, while the quality of these services and equipment may suffer. The unavailability or high cost of drilling rigs, pressure pumping equipment, supplies or qualified personnel can materially and adversely affect our operations and profitability. In order to secure drilling rigs and pressure pumping equipment, we have entered into certain contracts that extend over several months and or years. If demand for drilling rigs and pressure pumping equipment subside during the period covered by these contracts, the price we are required to pay may be significantly more than the market rate for similar services.

We depend on the skill, ability and decisions of third party operators of the oil and natural gas properties in which we have a non-operated working interest.

The success of the drilling, development and production of the oil and natural gas properties in which we have or expect to have a non-operating working interest is substantially dependent upon the decisions of such third-party operators and their diligence to comply with various laws, rules and regulations affecting such properties. The failure of any third-party operator to make decisions, perform their services, discharge their obligations, deal with regulatory agencies, and comply with laws, rules and regulations, including environmental laws and regulations in a proper manner with respect to properties in which we have an interest could result in material adverse consequences to our interest in such properties, including substantial penalties and compliance costs. Such adverse consequences could result in substantial liabilities to us or reduce the value of our properties, which could negatively affect our results of operations.

The success of our midstream operations segment depends upon our ability to continually obtain new sources of natural gas supply, and any decrease in demand, price, or supplies of natural gas could reduce our midstream revenues.

Our gathering systems and treating facilities are dependent on natural gas reserves and wells, from which production will naturally decline over time, which means that our cash flows associated with these facilities will also decline over time. To maintain or increase throughput levels on our gathering systems, we must continually obtain new natural gas supplies. The primary factors affecting our ability to connect new supplies of natural gas and attract new customers to our gathering systems and treating facilities are the level of successful drilling activity near our gathering systems and our ability to compete for commitments of additional volumes from third party producers.

Fluctuations in oil and natural gas prices can greatly affect production rates and investments by third parties in the development of new oil and natural gas reserves. Drilling activity generally decreases as oil and natural gas prices decrease. Other than our own drilling, we have no control over the level of drilling activity in the areas of our operations, the amount of reserves underlying the wells or the rate at which production from a well will decline. In addition, we have no control over third party producers or their production decisions, which are affected by, among other things, prevailing and projected energy prices, demand for hydrocarbons, the level of reserves, geological considerations, governmental regulations and the availability and cost of capital.

If we are unable to maintain or increase the throughput on our gathering systems and treating facilities because of decreased drilling activity in the areas in which we operate or because of an inability to connect new supplies of natural gas and attract new third party producers, then our midstream operations segment and financial results could be negatively affected.

We do not own all of the land on which our transportation pipelines and gathering and treating systems are located, which could disrupt our operations.

We do not own all of the land on which our gathering and treating systems have been constructed, and we are therefore subject to the possibility of increased costs to retain necessary land use. We obtain the rights to construct and operate our gathering and treating systems on land owned by third parties and governmental agencies for a specific period of time. Our loss of these rights, through our inability to renew right-of-way contracts or otherwise, could have a material adverse effect on our business, results of operations and financial condition.

Hedging transactions may limit our potential gains and increase our potential losses.

In order to manage our exposure to price risks in the marketing of our oil, natural gas, and natural gas liquids production, we have entered into oil, natural gas, and natural gas liquids price hedging arrangements with respect to a portion of our anticipated production and we may enter into additional hedging transactions in the future. While intended to reduce the effects of volatile oil, natural gas and natural gas liquids prices, such transactions may limit our potential gains and increase our potential losses if oil, natural gas and natural gas liquids prices were to rise substantially over the price established by the hedge. In addition, such transactions may expose us to the risk of loss in certain circumstances, including instances in which:

- our production is less than expected;
- there is a widening of price differentials between delivery points for our production; or

the counterparties to our hedging agreements fail to perform under the contracts.

We may be required to take non-cash asset write downs if oil and natural gas prices decline.

We may be required under full cost accounting rules to write down the carrying value of oil and natural gas properties if oil and natural gas prices decline or if there are substantial downward adjustments to our estimated proved reserves, increases in our estimates of development costs or deterioration in our exploration results. We utilize the full cost method of accounting for oil and natural gas exploration and development activities. Under full cost accounting, we are required by SEC regulations to perform a ceiling test each quarter. The ceiling test is an impairment test and generally establishes a maximum, or "ceiling," of the book value of oil and natural gas properties that is equal to the expected after tax present value (discounted at 10%) of the future net cash flows from proved reserves, including the effect of cash flow hedges when hedge accounting is applied, calculated using the unweighted arithmetic average of the first day of each month for the 12-month period ending at the balance sheet date. If the net book value of oil and natural gas properties (reduced by any related net deferred income tax liability and asset retirement obligation) exceeds the ceiling limitation, SEC regulations require us to impair or "write down" the book value of our oil and natural gas properties.

As of December 31, 2010, our net book value of oil and natural gas properties did not exceed our ceiling amount using the WTI unweighted 12-month average price $79.43 per Bbl for oil and natural gas liquids and the Henry Hub unweighted 12-month average of $4.38 per Mmbtu for natural gas. As of December 31, 2009, using $57.65 per Bbl for oil and $3.87 per Mmbtu for natural gas, our net book value of oil and natural gas properties exceeded the ceiling amount. As a result, we recorded a full cost ceiling test impairment before income taxes of approximately $106 million, $65 million after taxes. We also recorded full cost ceiling test impairments before tax at March 31, 2009 and December 31, 2008 of $1.7 billion and $1.0 billion, respectively. As ceiling test computations depend upon the calculated unweighted arithmetic average prices, it is impossible to predict the likelihood, timing and magnitude of any future impairments. Depending on the magnitude, a ceiling test write down could negatively affect our results of operations.

Costs associated with unevaluated properties, which were $2.4 billion at December 31, 2010, are not initially subject to the ceiling test limitation. Rather, we assess all items classified as unevaluated property on a quarterly basis for possible impairment or reduction in value based upon our intentions with respect to drilling on such properties, the remaining lease term, geological and geophysical evaluations, drilling results, the assignment of proved reserves, and the economic viability of development if proved reserves are assigned. These factors are significantly influenced by our expectations regarding future commodity prices, development costs, and access to capital at acceptable cost. 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 and the ceiling test limitation. Accordingly, a significant change in these factors, many of which are beyond our control, may shift a significant amount of cost from unevaluated properties into the full cost pool that is subject to amortization and the ceiling test limitation.

Our results of operations could be adversely affected as a result of non-cash goodwill impairments.

In conjunction with the recording of the purchase price allocation for several of our acquisitions, we recorded goodwill which represents the excess of the purchase price paid by us for those companies plus liabilities assumed, including deferred taxes recorded in connection with the respective acquisitions, over the estimated fair market value of the tangible net assets acquired.

The Financial Accounting Standard Board's (FASB) Accounting Standards Codification (ASC) 350, *Intangibles Goodwill and Other* (ASC 350) requires that intangible assets with indefinite lives, including

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goodwill, be evaluated on an annual basis for impairment or more frequently if an event occurs or circumstances change that could potentially result in impairment. The goodwill impairment test requires the allocation of goodwill and all other assets and liabilities to reporting units. If the fair value of the reporting unit is less than the book value (including goodwill), then goodwill is reduced to its implied fair value and the amount of the write down is charged against earnings. The assumptions we used in calculating our reporting unit fair value at the time of the test include our market capitalization and discounted future cash flows based on estimated reserves and production, future costs and future oil and natural gas prices. Adverse changes to any of these factors could lead to an impairment of all or a portion of our goodwill in future periods.

ITEM 1B. UNRESOLVED STAFF COMMENTS

None.

ITEM 2. PROPERTIES

A description of our properties is included in Item 1. *Business* and is incorporated herein by reference.

We believe that we have satisfactory title to the properties owned and used in our business, subject to liens for taxes not yet payable, liens incident to minor encumbrances, liens for credit arrangements and easements and restrictions that do not materially detract from the value of these properties, our interests in these properties, or the use of these properties in our business. We believe that our properties are adequate and suitable for us to conduct business in the future.

ITEM 3. LEGAL PROCEEDINGS

A description of our legal proceedings is included in Item 8. *Consolidated Financial Statements and Supplementary Data* Note *7, "Commitments and Contingencies,"* and is incorporated herein by reference.

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 determined, 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 consolidated operating results, financial position or cash flows.

Under rules promulgated by the SEC, administrative or judicial proceedings arising under any Federal, State or local provisions that have been enacted or adopted regulating the discharge of materials into the environment or 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 were formerly involved in natural gas exploration in the Fayetteville Shale play in North Central Arkansas. Our subsidiary, Hawk Field Services, constructed a pipeline to transport natural gas from wellheads. Hawk Field Services' activities were 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 of Engineers). 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

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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. Hawk Field Services sold its gathering and treating assets serving the Fayetteville Shale in conjunction with the Company's disposition of its Fayetteville Shale natural gas properties and, as a consequence, neither the Company nor Hawk Field Services currently have ongoing operations in Arkansas. The Company and the United States Department of Justice are currently in the process of finalizing a plea agreement, whereby Hawk Field Services is expected to plead guilty to three misdemeanor counts of violating the Endangered Species Act, pay a $350,000 fine, and contribute $150,000 toward environmental conservation efforts in the Fayetteville Shale area.

We are also involved in natural gas exploration in the Haynesville Shale in Louisiana. On July 27, 2009, we received a Cease and Desist Order from the Corps of Engineers 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 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 working with Corps to obtain the necessary authorizations for each of these well sites. The Company has negotiated a consent agreement and final order with EPA, whereby the Company has agreed to pay a $177,500 administrative penalty to resolve all liability for the alleged violations, which the Company expects to pay in the first quarter of 2011.

ITEM 4. REMOVED AND RESERVED

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PART II.

ITEM 5. MARKET FOR REGISTRANT'S COMMON EQUITY, RELATED STOCKHOLDER MATTERS AND ISSUER PURCHASES OF EQUITY SECURITIES

Our common stock trades on the New York Stock Exchange (NYSE) under the symbol HK. The following table sets forth the quarterly high and low sales prices per share of our common stock as reported on the New York Stock Exchange from January 1, 2009 through December 31, 2010.

	High	Low
2010		
First Quarter	$ 27.36	$ 18.98
Second Quarter	23.80	14.00
Third Quarter	18.39	14.32
Fourth Quarter	20.05	16.04
2009		
First Quarter	$ 22.87	$ 14.89
Second Quarter	26.91	18.50
Third Quarter	25.81	18.01
Fourth Quarter	28.49	20.45

We have never paid cash dividends on our common stock. We intend to retain earnings for use in the operation and expansion of our business and therefore do not anticipate declaring cash dividends on our common stock in the foreseeable future. Any future determination to pay dividends on common stock will be at the discretion of the board of directors and will be dependent upon then existing conditions, including our prospects, and such other factors, as the board of directors deems relevant. We are also restricted from paying cash dividends on common stock under our Senior Credit Agreement and under the terms of the indentures governing our other long-term debt.

Approximately 525 stockholders of record as of December 31, 2010 held our common stock. In many instances, a registered stockholder is a broker or other entity holding shares in street name for one or more customers who beneficially own the shares.

Changes in Securities, Use of Proceeds and Issuer Purchases of Equity Securities

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 withholding obligations during the three months ended December 31, 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
October 2010	621	$ 17.03		
November 2010	1,516	17.52		
December 2010	738	18.43		

(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.*

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Five-Year Stock Performance Graph

The following common stock performance graph shows the performance of Petrohawk common stock through December 31, 2010. As required by applicable rules of the SEC, the performance graph shown below was prepared based on the following assumptions:

A $100 investment was made in Petrohawk common stock and each index on December 31, 2005.

All quarterly dividends were reinvested at the average of the closing stock prices at the beginning and end of the quarter.

The indices in the performance graph compare the annual cumulative total stockholder return on Petrohawk common stock with the cumulative total return of the Standard and Poor's 500 Index (S&P 500), the S&P 500 Oil and Gas Exploration & Production Index and a peer group index comprised of 12 United States companies engaged in oil and natural gas operations whose stocks were traded on the NASDAQ or the NYSE during the period from December 31, 2005 through December 31, 2010. The companies that comprise the peer group are Cabot Oil & Gas, Corp. (COG), Chesapeake Energy Corp. (CHK), Cimarex Energy Co. (XEC), Comstock Resources Inc. (CRK), EXCO Resources Inc. (XCO), Forest Oil Corp. (FST), Newfield Exploration Co. (NFX), Plains Exploration & Production Company (PXP), Range Resources Corp. (RRC), Sandridge Energy Inc. (SD), Southwestern Energy Co. (SWN), and St. Mary Land & Exploration Co. (SM), collectively referred to as (Peer Group Index).

The Company intends to include the S&P 500 Oil and Gas Exploration & Production Index rather than the Peer Group Index in future filings because the Company believes that this index is a more appropriate and consistent measure of the performance of the industry in which the Company operates.

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Value of Initial $100 Investment (End of Year)

Year	12/31/2005	12/31/2006	12/31/2007	12/31/2008	12/31/2009	12/31/2010
Petrohawk	$ 100.00	$ 86.99	$ 130.94	$ 118.23	$ 181.47	$ 138.05
Peer Group Index	100.00	99.08	133.18	73.29	120.30	126.49
S&P 500	100.00	115.79	122.16	76.96	97.33	111.99
S&P 500 Oil & Gas Exploration & Production Index	100.00	104.65	151.15	98.92	140.56	153.60

ITEM 6. SELECTED FINANCIAL DATA

The following table presents selected historical financial data derived from our consolidated financial statements. The following data is only a summary and should be read with our historical consolidated financial statements and related notes contained in this document.

	Years Ended December 31,				
	2010	2009	2008	2007	2006
	(In thousands, except per share data)				
Income Statement Data:					
Total operating revenues	$ 1,597,856	$ 1,070,676	$ 1,090,864	$ 883,405	$ 587,762
Income (loss) from operations[(1)(2)]	367,744	(1,806,164)	(536,087)	250,663	154,540
Income (loss) from continuing operations, net of income taxes	234,652	(1,022,329)	(386,867)	52,906	116,563
Net income (loss)	188,668	(1,025,451)	(388,052)	52,897	116,563
Net income (loss) available to common stockholders	188,668	(1,025,451)	(388,052)	52,897	116,346
Income (loss) from continuing operations per share of common stock:[(3)]					
Basic	$ 0.78	$ (3.65)	$ (1.77)	$ 0.31	$ 0.95
Diluted	$ 0.78	$ (3.65)	$ (1.77)	$ 0.31	$ 0.92

	As of December 31,				
	2010	2009	2008	2007	2006
	(In thousands)				
Balance sheet data:					
Working capital deficit	$ (219,286)	$ (313,182)	$ (77,880)	$ (171,304)	$ (85,307)
Total assets	7,624,442	6,662,071	6,907,329	4,672,439	4,279,656
Total long-term debt[(4)(5)]	2,612,852	2,592,544	2,283,874	1,595,127	1,326,239
Stockholders' equity	3,544,286	3,323,672	3,404,910	2,008,897	1,928,344

(1) *2009 includes an approximate $1.8 billion before taxes full cost ceiling test impairment charge.*

(2) *2008 includes an approximate $1.0 billion before taxes full cost ceiling test impairment charge.*

(3) *No cash dividends were declared or paid for any periods presented.*

(4) *Amount excludes the current portion of deferred premiums on derivatives for all periods presented.*

(5) *For 2010, amount excludes $0.2 million of 9.875% senior notes due 2011 which have been classified as current at December 31, 2010.*

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ITEM 7. 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 condition. Our consolidated financial statements and the accompanying notes included elsewhere in this Annual Report on Form 10-K contain additional information that should be referred to when reviewing this material.

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 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 three 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 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 which was formed to integrate our active drilling program with activities of third parties to develop additional gathering and treating capacity. Hawk Field Services currently serves the Haynesville Shale and Lower Bossier Shale in North Louisiana through our investment in KinderHawk Field Services and the Eagle Ford Shale in South Texas.

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 that we believe have significant development and exploration opportunities. In the past few years, we significantly expanded our leasehold position in resource plays, particularly in the Haynesville Shale play in Northern Louisiana and East Texas and the Eagle Ford Shale play in South Texas, where we believe we can apply our technical experience and economies of scale to increase production and proved reserves while lowering unit lease operating costs. 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 primary lease term (generally three to five years) or the lease will expire. Lease expirations are expected to be an important factor in determining our capital expenditures focus over the next nine to twelve months.

At December 31, 2010, our estimated total proved oil and natural gas reserves, as prepared by our independent reserve engineering firm, Netherland, Sewell, were approximately 3,392 Bcfe, consisting of 3,110 Bcf of natural gas, 20 MMBbls of oil and 27 MMBbls of natural gas liquids. Approximately 35% of our proved reserves were classified as proved developed. We maintain operational control of approximately 82% of our proved reserves. Production for the fourth quarter of 2010 averaged 761 million Mmcfe/d. Full year 2010 production averaged 675 Mmcfe/d compared to 502 Mmcfe/d in 2009. Our total operating revenues for 2010 were approximately $1.6 billion.

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

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other factors. Accordingly, finding and developing oil and natural gas reserves at economical costs is critical to our long-term success.

Our 2010 budget was focused on the development of non-proved reserve locations in our Haynesville, Lower Bossier, Eagle Ford and Fayetteville Shale plays so that we could hold our acreage in these areas. In addition, we believed these projects offered us the potential for high internal rates of return and reserve growth which is evidenced by our actual 2010 operating results. In 2010, we were also determined to maintain our liquidity position despite the large amount of capital that was required to execute our aggressive 2010 operational plan. We were able to accomplish this task by completing a number of asset dispositions that also enabled us to highgrade our asset portfolio and continue to lower our per unit operating costs. In 2010, we sold approximately $1.2 billion in producing 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, approximately $575 million for the sale of our Fayetteville Shale area in 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 $917 million (including approximately $42 million in closing adjustments) for a 50% interest in our Haynesville Shale gathering and treating business in North Louisiana.

We expect to spend approximately $2.3 billion of capital during 2011, of which $1.9 billion is expected to be allocated for drilling and completions, $200 million is expected to be allocated for midstream operations and $200 million will be allocated for potential leasehold acquisitions. Of the $1.9 billion budget for drilling and completions, $900 million is planned for the Haynesville and Lower Bossier Shales, which will enable us to fulfill our held-by-production goals, $900 million is budgeted for the Eagle Ford Shale, and approximately $100 million is budgeted for various other projects. Our 2011 drilling and completion budget 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 as our lease-holding activities are fulfilled. Our 2011 program will emphasize the development of our extensive condensate-rich properties, largely in the Eagle Ford Shale, and a shift away from dry gas development in our core areas. The $1.9 billion drilling and completion budget for 2011 is based on our current view of market conditions, our ability 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.

We expect to fund our 2011 capital budget with cash flows from operations, proceeds from potential asset dispositions, a portion of the proceeds from our recent senior note offering and borrowings under our Senior Credit Agreement. We strive to maintain financial flexibility and may access capital markets as necessary to maintain substantial borrowing capacity under our Senior Credit Agreement, facilitate drilling on our large undeveloped acreage position and selectively expand our acreage position and infrastructure projects. In the event our cash flows or proceeds from potential asset dispositions are materially less than anticipated and other sources of capital we historically have utilized are not available on acceptable terms, we may curtail our capital spending.

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 joint venture pursuant to a Formation and Contribution Agreement (Contribution Agreement). The joint venture entity, KinderHawk Field Services LLC (KinderHawk), engages in the natural gas midstream business in Northwest Louisiana, focused on the Haynesville and Lower Bossier Shales. 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 $917 million in cash ($875 million for a 50% membership interest in KinderHawk and $42 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 $917 million to us. The joint venture had an economic effective date of January 1, 2010, and Hawk Field Services continued to operate the business until September 30, 2010, at which date Hawk Field Services 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 to KinderHawk agreed upon minimum annual quantities of natural gas from our operated wells producing from the Haynesville and Lower Bossier Shales in North Louisiana through May 2015, 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 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 continuously monitor our liquidity and the capital markets and 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 (net of discounts and expenses). In 2010, we redeemed our $775 million 2013 Notes in August with the issuance of $825 million of Senior Notes due in 2018 (2018 Notes). In early 2011, we will redeem our $275 million 2012 Notes, which have been called for redemption, with a portion of the proceeds from the issuance of $400 million of additional 2018 Notes, which is discussed further below.

Our Senior Credit Agreement provides for a $2.0 billion credit facility. As of December 31, 2010, the borrowing base was approximately $1.65 billion, $1.55 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 is 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 and is calculated quarterly. As of December 31, 2010, the midstream component of the borrowing base was limited to approximately $38 million based on the midstream EBITDA limitation. Our ability to utilize the full amount of our borrowing capacity is influenced by a variety of factors, including redeterminations of our borrowing base, 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, increasing to $1 billion upon redemption of the 2012 Notes) and a percentage (the most restrictive indenture limit currently being 20%, but increasing to 30% upon redemption of the 2012 Notes) of our adjusted consolidated net tangible assets (as defined in all of our indentures), which is determined using discounted future net revenues from proved oil and natural gas reserves as of the end of each year. As of December 31, 2010, we had $146 million of debt outstanding under the Senior Credit Agreement and $1.4 billion of additional borrowing capacity available.

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 redeem our $775 million outstanding 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 million in the third quarter of 2010. These charges are recorded in *"Interest expense and other"* on the 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.

On January 31, 2011, we completed the issuance of an additional $400 million aggregate principal amount of our 2018 Notes. A portion of the proceeds from this issuance will be utilized to redeem our $275 million 7.125% senior notes due 2012, which have been called for redemption. For further discussion of this transaction, see Item 8. *Consolidated Financial Statements and Supplementary Data* Note 16 *"Subsequent Event."*

In conjunction with the KinderHawk joint venture, we are obligated to commit up to an additional $78.2 million, as of December 31, 2010, in capital contributions to KinderHawk during 2011, if KinderHawk requires capital to fund its capital expenditures. Additional contributions above this amount can be made at our discretion. Capital contributions to KinderHawk could impact our development plans by reducing the amount of capital available to fund our drilling program. Capital contributions to be made to KinderHawk will be factored into our overall analysis of capital resources and liquidity on an ongoing basis.

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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 source of cash in 2010 was from operating activities. Our primary sources of cash in 2009 and 2008 were from operating and financing activities. In 2009 and 2008, proceeds from the sale of common stock, the issuance of new senior debt and cash received from operations were offset by repayments of borrowings under our Senior Credit Agreement and cash used in investing activities to fund our drilling program and acquisition activities, net of any divestiture 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 commodity prices and our overall 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 fluctuations 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 sales.

	Years Ended December 31,		
	2010	2009	2008
		(In thousands)	
Cash flows provided by operating activities	$ 505,627	$ 679,127	$ 608,955
Cash flows used in investing activities	(396,566)	(1,866,638)	(3,030,450)
Cash flows (used in) provided by financing activities	(108,981)	1,182,139	2,426,566
Net increase (decrease) in cash	$ 80	$ (5,372)	$ 5,071

Operating Activities. Net cash flows provided by operating activities were $505.6 million, $679.1 million and $609.0 million for the years ended December 31, 2010, 2009, and 2008, respectively. Key drivers of net operating cash flows are commodity prices, production volumes and operating costs.

Net cash provided by operating activities decreased $173.5 million in 2010 primarily due to the decrease in cash received on settled derivative contracts from $375.1 million in 2009 to $243.0 million in 2010. This decrease was partially offset by a 34% increase in our average daily production volumes due to our continued drilling success primarily in the Haynesville, Fayetteville and Eagle Ford Shales. Production for 2010 averaged 675 Mmcfe/d compared to 502 Mmcfe/d during 2009. Also contributing to the increase was the increase in our natural gas equivalent price of $0.50 per Mcfe to $4.49 per Mcfe from $3.99 per Mcfe in the prior year. As a result of our drilling program, we expect to continue to increase our production volumes throughout 2011. However, we are unable to predict future production levels or future commodity prices with certainty, and, therefore, we cannot provide assurance about future levels of net cash provided by operating activities.

Net cash flows provided by operating activities increased in 2009 primarily due to our 65% increase in our average daily production volumes due to our drilling success in the Haynesville, Fayetteville and Eagle Ford Shales, which was partially offset by a 56% decrease in our average realized natural gas equivalent price compared to the same period in 2008.

Net cash flows provided by operating activities increased in 2008 primarily due to our 21% increase in average realized natural gas equivalent price, partially offset by a 4% decrease in production volumes due to the sale of our Gulf Coast properties during the fourth quarter of 2007.

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Investing Activities. The primary driver of cash used in investing activities is capital spending, inclusive of acquisitions and net of divestitures. Net cash used in investing activities was $396.6 million, $1.9 billion and $3.0 billion for the years ended December 31, 2010, 2009 and 2008, respectively.

In 2010, we spent $2.4 billion on oil and natural gas capital expenditures. We participated in the drilling of 906 gross wells (218.3 net wells). We spent an additional $258.9 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.

In 2010, we purchased and redeemed $1.1 billion of marketable securities. These marketable securities were classified and accounted for as trading securities.

In 2010, we had a net decrease in restricted cash of $213.7 million. Restricted cash was used to fund a portion of our 2010 oil and natural gas acquisitions.

On December 22, 2010, we completed the sale of our interest in natural gas properties and other operating assets in the Fayetteville Shale for approximately $575 million in cash, before customary closing adjustments. Proceeds from the sale of the interest in natural gas properties 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 October 1, 2010.

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 and Lower Bossier Shales. Hawk Field Services contributed to KinderHawk our Haynesville Shale gathering and treating business in Northwest Louisiana, and Kinder Morgan contributed approximately $917 million in cash ($875 million for a 50% membership interest in KinderHawk and $42 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 $917 million to us. During 2010, we have made contributions of $23.4 million to KinderHawk to partially fund the 2010 capital program and have received distributions of $21.4 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 all of which has been spent as of December 31, 2010.

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 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.

In 2009, we spent $1.7 billion on acquisitions of oil and natural gas properties and capital expenditures. We participated in the drilling of 626 gross wells (162.1 net wells). We spent an additional

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$309.5 million on other operating property and equipment expenditures, primarily to fund the completion of gathering systems in the Fayetteville Shale in Arkansas and the development of our gathering systems in the Haynesville Shale in Louisiana and the Eagle Ford Shale in Texas.

In 2009, we redeemed a net $123.0 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. No amounts remained outstanding as of December 31, 2009.

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 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, we have the contractual right to extend firm supply through 2019. The purchase price was allocated to the transportation related contracts at fair market value and is amortized on a straight line basis over the life of the extended agreement.

On October 30, 2009, we sold our Permian Basin properties for $376 million in cash, before customary closing adjustments. Proceeds from the sale were recorded as a reduction to the carrying value of our full cost pool. In conjunction with the closing of this sale, we deposited the remaining net proceeds of $331 million with a qualified intermediary to facilitate potential like-kind exchange transactions ($37.6 million was previously received as a deposit). As of December 31, 2009, $213.7 million remained with the intermediary.

In 2008, we spent $3.1 billion on acquisitions of oil and natural gas properties and capital expenditures. Our acquisitions were partially funded by the remaining restricted cash that we had deposited with a qualified intermediary to facilitate like-kind exchange transactions following the sale of our Gulf Coast properties in November 2007. We participated in the drilling of 739 gross wells (267.4 net wells) in 2008. We spent an additional $164.8 million on other operating property and equipment during 2008 as well, primarily to fund the development of gathering systems primarily in the Fayetteville Shale in Arkansas and the beginning stages of the development of our gathering systems in the Haynesville Shale in Louisiana.

In 2008, we used a portion of the funds from our debt and equity offerings to purchase a net $123.0 million of marketable securities. These marketable securities were classified and accounted for as trading securities and were used primarily to fund our leasing and acquisition activities in the Haynesville Shale.

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

Financing Activities. Net cash flows used in financing activities were $109.0 million for the year ended December 31, 2010 which resulted primarily from net repayments on our Senior Credit Agreement and the net impact of our debt issuance and refinancing activities in 2010 of approximately $87.4 million. Net cash flows provided by financing activities were $1.2 billion and $2.4 billion for the years ended December 31, 2009 and 2008, respectively.

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

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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 repurchase such 2013 Notes. The remaining 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 expenses.

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 to eligible purchasers of an aggregate principal amount of $600 million 10.5% senior notes due August 1, 2014 (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.

On August 15, 2008, we sold an aggregate of 28.8 million shares of our common stock in an underwritten public offering. The net proceeds from the sale were approximately $734 million, after deducting underwriting discounts and commissions and expenses.

On June 19, 2008, we issued $300 million aggregate principal amount of 7.875% senior notes due 2015 (2015 Notes) in a private placement to eligible purchasers. The net proceeds from the sale of the 2015 Notes were approximately $294 million, after deducting the initial purchaser's discount and offering expenses.

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

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

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

Capital financing and excess cash flow are used to repay debt to the extent available. In 2010, we had net repayments of borrowings under our Senior Credit Agreement of $87.4 million primarily due to the proceeds received from asset sales offset by the cash requirements of our drilling activities. As of December 31, 2010, our Senior Credit Agreement had a $1.65 billion borrowing base and we had $146 million outstanding.

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Cash flows provided by financing activities include net borrowings of $282.0 million and $677.7 million for the years ended December 31, 2009 and 2008, respectively, primarily due to our acquisition activities and our ongoing drilling activities.

Contractual Obligations

We believe we have a significant degree of flexibility to adjust the level of our future capital expenditures as circumstances warrant. Our level of capital expenditures will vary in future periods depending on the success we experience in our acquisition, developmental 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 by payment periods as of December 31, 2010.

	Payments Due by Period				
Contractual Obligations	**Total**	**2011**	**2012-2013**	**2014-2015**	**2016 and Beyond**
			(In thousands)		
Senior revolving credit facility	$ 146,000	$	$	$ 146,000	$
7.25% $825 million senior notes[(1)]	825,000				825,000
10.5% $600 million senior notes[(2)]	600,000			600,000	
7.875% $800 million senior notes	800,000			800,000	
7.125% $275 million senior notes[(3)]	272,375		272,375		
9.875% senior notes	224	224			
Interest expense on long-term debt[(4)]	1,023,151	216,316	398,657	251,170	157,008
Deferred premiums on derivatives[(5)]	25,381	14,566	10,815		
Rig commitments	297,031	183,990	110,751	2,290	
Gathering and transportation contracts	1,946,576	127,844	371,551	360,726	1,086,455
Pipeline and well equipment	127,279	127,279			
Other commitments[(6)]	59,902	45,269	14,633		
Operating leases	29,205	6,901	14,000	7,276	1,028
Total contractual obligations	$ 6,152,124	$ 722,389	$ 1,192,782	$ 2,167,462	$ 2,069,491

(1) *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. On January 31, 2011, we issued an additional $400 million of these notes which are not reflected in the table. See "7.25% Senior Notes", below for further details.*

(2) *Excludes $37.9 million unamortized discount recorded in conjunction with the issuance of the notes. See "10.5% Senior Notes" below for more details.*

(3) *Excludes a net $3.5 million unamortized discount recorded in conjunction with our merger with KCS. See "7.125% Senior Notes" below for more details.*

(4) *Future interest expense was calculated based on interest rates and amounts outstanding at December 31, 2010 less required annual repayments.*

(5) *Approximately $14.6 million of this amount has been classified as current at December 31, 2010.*

(6) *Other commitments pertains to exploration, development and production activities including, among other things, commitments for obtaining and processing seismic data and fracture stimulation services.*

The contractual obligations table does not include obligations to taxing authorities due to the uncertainty surrounding the ultimate settlement of amounts and timing of these obligations. In addition, amounts related to our asset retirement obligations are not included in the table above given

the uncertainty regarding the actual timing of such expenditures. The total amount of asset retirement obligations at December 31, 2010 is $31.7 million.

On May 21, 2010, we created a joint venture with Kinder Morgan, KinderHawk, which engages in the natural gas midstream business in Northwest Louisiana, focused on the Haynesville and Lower Bossier Shales. As part of this transaction, we are committed to contribute up to an additional $78.2 million as of December 31, 2010 in capital during 2011 in the event KinderHawk requires capital to finance its planned capital expenditures. In addition, we are obligated to deliver to KinderHawk agreed upon minimum annual quantities of natural gas from our operated wells producing from the Haynesville and Lower Bossier Shales in North Louisiana through May 2015, or in the alternative, pay an annual true-up fee to KinderHawk if such minimum annual quantities are not delivered. These obligations are not reflected in the amounts in the table above. We pay to KinderHawk negotiated gathering and treating fees, subject to an annual inflation adjustment factor.

Senior Revolving Credit Facility

Effective August 2, 2010, we amended and restated our existing credit facility dated October 14, 2009 by entering into the Fifth Amended and Restated Senior Revolving Credit Agreement (the Senior Credit Agreement), among us, 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 December 31, 2010, the borrowing base was approximately $1.65 billion, $1.55 billion of which related to our oil and natural gas properties and up to $100 million (currently limited as described below) related to our midstream assets. The portion of the borrowing base relating to our oil and natural gas properties is redetermined on a semi-annual basis (with us 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 relating to our midstream assets is limited to the lesser of $100 million or 3.5 times midstream EBITDA, and is calculated quarterly. As of December 31, 2010, the midstream component of the borrowing base was limited to approximately $38 million based on midstream EBITDA. Our 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 unsecured senior or senior subordinated notes that we may issue. In January 2011, we issued an additional $400 million aggregate principal amount of our 7.25% senior notes due 2018, as discussed below, and accordingly, our borrowing base was reduced to approximately $1.6 billion.

Amounts outstanding under the Senior Credit Agreement bear interest at specified margins over LIBOR of 2.00% to 3.00% for Eurodollar loans or at specified margins over ABR of 1.00% to 2.00% for ABR loans. Such margins will fluctuate based on the percentage utilization of the facility. Borrowings under the Senior Credit Agreement are secured by first priority liens on substantially all of our 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, our 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, we are 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 December 31, 2010, we were in compliance with our financial debt covenants under the Senior Credit Agreement.

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7.25% Senior Notes

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 2018 (the 2018 Notes) at a purchase price of 100% of the principal amount of the 2018 Notes.

In connection with the sale of the 2018 Notes, we entered into a Registration Rights Agreement, dated August 17, 2010, among us and the initial purchasers (the Registration Rights Agreement). Pursuant to the Registration Rights Agreement, we 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 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 ours and rank equally with all of our current and future senior indebtedness. The 2018 Notes are jointly and severally, fully and unconditionally guaranteed on a senior unsecured basis by our 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.

On January 31, 2011, we completed the issuance of an additional $400 million aggregate principal amount of our 2018 Notes. We will utilize a portion of the proceeds from this issuance to redeem our 7.125% $275 million senior notes due 2012, which have been called for redemption. For further discussion of this transaction, see *Item 8 Consolidated Financial Statements and Supplementary Data* Note 16, *"Subsequent Event."*

10.5% Senior Notes

On January 27, 2009, we issued $600 million principal amount of our 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 us, U.S. Bank National Association, as trustee, and our subsidiaries named therein as guarantors. The 2014 Notes bear interest at 10.5% per annum, payable semi-annually on February 1 and August 1 of each year, commencing on August 1, 2009. The 2014 Notes will mature on August 1, 2014. The 2014 Notes were priced at 91.279% of the face value to yield 12.7% to maturity. The 2014 Notes are senior unsecured obligations and rank equally with all of our current and future senior indebtedness.

In conjunction with the issuance of the $600 million 2014 Notes, we 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 $37.9 million at December 31, 2010.

7.875% Senior Notes

On May 13, 2008 and June 19, 2008, we issued $500 million principal amount and $300 million principal amount, respectively, of our 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 us, U.S. Bank Trust National Association, as trustee, and our subsidiaries named therein as guarantors. The 2015 Notes bear interest at a rate of 7.875% per annum, payable semi-annually on June 1 and December 1 of each year, commencing December 1, 2008. The 2015 notes will mature on June 1, 2015. The 2015 Notes are senior unsecured obligations and rank equally with all of our current and future senior indebtedness. The 2015 Notes were issued at par value, with no discount or premium recorded.

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9.125% Senior Notes

On July 12 and 27, 2006, we issued a total of $775 million principal amount 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 us, our subsidiaries named therein as guarantors, and U.S. Bank National Association, as trustee. We issued the 2013 Notes in two tranches, $650 million on July 12, 2006 and $125 million on July 27, 2006. The additional $125 million in 2013 Notes were issued pursuant to the same Indenture at 101.125% of the face amount. We applied the net proceeds from the sale of the additional 2013 Notes to repay indebtedness outstanding under our revolving credit facility. The $650 million tranche of 2013 Notes were issued at 98.735% of the face amount for gross proceeds of approximately $642.0 million, before estimated offering expenses and the initial purchasers' discount. We applied a portion of the net proceeds from the sale of the 2013 Notes to fund the cash paid by us to the KCS stockholders in connection with our merger with KCS and our repurchase of the 9.875% notes due 2011 (2011 Notes) pursuant to a tender offer we concluded in July 2006.

In conjunction with the issuance of the $650 million 2013 Notes, we 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 December 31, 2010. In conjunction with the issuance of the $125 million 2013 Notes, we 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 December 31, 2010.

Upon issuance of the 2018 Notes, as discussed above, on August 3, 2010, we 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, we announced that it had received the requisite consents to amend the 2013 Notes Indenture, and we 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 Securities Exchange Commission (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 when we accepted and repurchased 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, we 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 repurchase the tendered 2013 Notes. Approximately $116.0 million in aggregate principal amount of 2013 Notes were not tendered.

On August 19, 2010, we elected to exercise our right under the 2013 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 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.

7.125% Senior Notes

In our merger with KCS, we assumed (pursuant to the Second Supplemental Indenture relating to the 7.125% senior notes, also referred to as the 2012 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 7.125% senior notes due 2012. The 2012 Notes are guaranteed on an unsubordinated, unsecured basis by all of our current subsidiaries. Interest on the 2012 Notes is payable semi-annually, on each April 1 and October 1.

In conjunction with the assumption of the 7.125% Notes from KCS, we 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 was $3.5 million at December 31, 2010.

See Item 8. *Consolidated Financial Statements and Supplementary Data* Note 16, "*Subsequent Event",* for discussion of the anticipated redemption of the 2012 Notes.

9.875% Senior Notes

On April 8, 2004, Mission Resources Corporation (Mission) issued $130.0 million of its 9.875% senior notes due 2011 (the 2011 Notes). We assumed these notes upon the closing of our merger with Mission. In conjunction with our merger with KCS, we extinguished substantially all of the 2011 Notes.

Off-Balance Sheet Arrangements

At December 31, 2010, we did not have any material off-balance sheet arrangements.

Critical Accounting Policies and Estimates

The discussion and analysis of our financial condition and results of operations are based upon our consolidated financial statements, which have been prepared in accordance with accounting principles generally accepted in the United States. The preparation of our consolidated financial statements requires us to make estimates and assumptions that affect our reported results of operations and the amount of reported assets, liabilities and proved oil and natural gas reserves. Some accounting policies involve judgments and uncertainties to such an extent that there is reasonable likelihood that materially different amounts could have been reported under different conditions, or if different assumptions had been used. Actual results may differ from the estimates and assumptions used in the preparation of our consolidated financial statements. Described below are the most significant policies we apply in preparing our consolidated financial statements, some of which are subject to alternative treatments under accounting principles generally accepted in the United States. We also describe the most significant estimates and assumptions we make in applying these policies. We discussed the development, selection and disclosure of each of these with our audit committee. See Results of Operations above and Item 8. *Consolidated Financial Statements and Supplementary Data* Note 1, "*Summary of Significant Events and Accounting Policies,"* for a discussion of additional accounting policies and estimates made by management.

Oil and Natural Gas Activities

Accounting for oil and natural gas activities is subject to unique rules. Two generally accepted methods of accounting for oil and natural gas activities are available successful efforts and full cost. The most significant differences between these two methods are the treatment of unsuccessful exploration costs and the manner in which the carrying value of oil and natural gas properties are amortized and evaluated for impairment. The successful efforts method requires unsuccessful exploration costs to be expensed as they are incurred upon a determination that the well is uneconomical while the full cost method provides for the capitalization of these costs. Both methods generally provide for the periodic amortization of capitalized costs based on proved reserve quantities. Impairment of oil and natural gas properties under the successful efforts method is based on an evaluation of the carrying value of individual oil and natural gas properties against their estimated fair value, while impairment under the full cost method requires an evaluation of the carrying value of oil

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and natural gas properties included in a cost center against the net present value of future cash flows from the related proved reserves, using the unweighted arithmetic average of the first day of the month for each of the 12-month prices for oil and natural gas within the period, holding prices and costs constant and applying a 10% discount rate.

Full Cost Method

We use the full cost method of accounting for our oil and natural gas activities. Under this method, all costs incurred in the acquisition, exploration and development of oil and natural gas properties are capitalized into a cost center (the amortization base). Such amounts include the cost of drilling and equipping productive wells, dry hole costs, lease acquisition costs and delay rentals. All general and administrative costs unrelated to drilling activities are expensed as incurred. The capitalized costs of our oil and natural gas properties, plus an estimate of our future development and abandonment costs are amortized on a unit-of-production method based on our estimate of total proved reserves. Our financial position and results of operations could have been significantly different had we used the successful efforts method of accounting for our oil and natural gas activities.

Proved Oil and Natural Gas Reserves

Estimates of our proved reserves included in this report are prepared in accordance with accounting principles generally accepted in the United States and SEC guidelines. Our engineering estimates of proved oil and natural gas reserves directly impact financial accounting estimates, including depreciation, depletion and amortization expense and the full cost ceiling test limitation. Proved oil and natural gas reserves are the estimated quantities of oil and natural gas reserves that geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under defined economic and operating conditions. The process of estimating quantities of proved reserves is very complex, requiring significant subjective decisions in the evaluation of all geological, engineering and economic data for each reservoir. The accuracy of a reserve estimate is a function of: (i) the quality and quantity of available data; (ii) the interpretation of that data; (iii) the accuracy of various mandated economic assumptions and (iv) the judgment of the persons preparing the estimate. The data for a given reservoir may change substantially over time as a result of numerous factors, including additional development activity, evolving production history and continual reassessment of the viability of production under varying economic conditions. Changes in oil and natural gas prices, operating costs and expected performance from a given reservoir also will result in revisions to the amount of our estimated proved reserves.

Our estimated proved reserves for the years ended December 31, 2010, 2009 and 2008 were prepared by Netherland, Sewell, an independent oil and natural gas reservoir engineering consulting firm. For more information regarding reserve estimation, including historical reserve revisions, refer to Item 8. Consolidated Financial Statements and Supplementary Data "*Supplemental Oil and Gas Information (Unaudited).*"

Depreciation, Depletion and Amortization

Our rate of recording depreciation, depletion and amortization expense (DD&A) is primarily dependent upon our estimate of proved reserves, which is utilized in our unit-of-production method calculation. If the estimates of proved reserves were to be reduced, the rate at which we record DD&A expense would increase, reducing net income. Such a reduction in reserves may result from calculated lower market prices, which may make it non-economic to drill for and produce higher cost reserves. A five percent positive or negative revision to proved reserves would decrease or increase the DD&A rate by approximately $0.10 per Mcfe.

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Full Cost Ceiling Test Limitation

Under the full cost method, we are subject to quarterly calculations of a ceiling or limitation on the amount of our oil and natural gas properties that can be capitalized on our balance sheet. If the net capitalized costs of our oil and natural gas properties exceed the cost center ceiling, we are subject to a ceiling test write down to the extent of such excess. If required, it would reduce earnings and impact stockholders' equity in the period of occurrence and result in lower amortization expense in future periods. The discounted present value of our proved reserves is a major component of the ceiling calculation and represents the component that requires the most subjective judgments. However, the associated prices of oil and natural gas reserves that are included in the discounted present value of the reserves do not require judgment. The ceiling calculation dictates that we use the unweighted arithmetic average price of oil and natural gas as of the first day of each month for the 12-month period ending at the balance sheet date. If average oil and natural gas prices decline, or if we have downward revisions to our estimated proved reserves, it is possible that write downs of our oil and natural gas properties could occur in the future.

If the unweighted arithmetic average price of oil and natural gas as of the first day of each month for the 12-month period ended December 31, 2010 had been 10% lower while all other factors remained constant, our ceiling amount related to our net book value of oil and natural gas properties would have been reduced approximately $802 million. This reduction would not have resulted in a full costing ceiling impairment.

Future Development Costs

Future development costs include costs incurred to obtain access to proved reserves such as drilling costs and the installation of production equipment. Future abandonment costs include costs to dismantle and relocate or dispose of our production facilities, gathering systems and related structures and restoration costs. We develop estimates of these costs for each of our properties based upon their geographic location, type of production structure, well depth, currently available procedures and ongoing consultations with construction and engineering consultants. Because these costs typically extend many years into the future, estimating these future costs is difficult and requires management to make judgments that are subject to future revisions based upon numerous factors, including changing technology and the political and regulatory environment. We review our assumptions and estimates of future development and future abandonment costs on an annual basis. A five percent decrease or increase in future development and abandonment costs would decrease or increase the DD&A rate by approximately $0.06 per Mcfe.

Asset Retirement Obligations

We have significant obligations to remove tangible equipment and facilities associated with our oil and natural gas wells and our gathering systems, and to restore land at the end of oil and natural gas production operations. Our removal and restoration obligations are associated with plugging and abandoning wells and our gathering systems. Estimating the future restoration and removal costs is difficult and requires us to make estimates and judgments because most of the removal obligations are many years in the future and contracts and regulations often have vague descriptions of what constitutes removal. Asset removal technologies and costs are constantly changing, as are regulatory, political, environmental, safety and public relations considerations. Inherent in the present value calculations are numerous assumptions and judgments including the ultimate settlement amounts, inflation factors, credit adjusted discount rates, timing of settlements and changes in the legal, regulatory, environmental and political environments.

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Accounting for Derivative Instruments and Hedging Activities

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. From time to time, we may hedge a portion of our forecasted oil, natural gas, and natural gas liquids production. Derivative contracts entered into by us have consisted of transactions in which we hedge the variability of cash flow related to a forecasted transaction. We elected to not designate any of our positions for hedge accounting. Accordingly, we record the net change in the mark-to-market valuation of these positions, as well as payments and receipts on settled contracts, in *"Net gain on derivative contracts"* on the consolidated statements of operations.

Goodwill

We account for goodwill in accordance with ASC 350, *Intangibles Goodwill and Other* (ASC 350). 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 requires that intangible assets with indefinite lives, including goodwill, be evaluated on an annual basis for impairment or more frequently if an event occurs or circumstances change that could potentially result in impairment. The goodwill impairment test requires the allocation of goodwill and all other assets and liabilities to reporting units. We have determined that we have two reporting units: oil and natural gas production and midstream operations. All of our goodwill has been allocated to our oil and natural gas production segment as all of our historical goodwill relates to our acquisitions of oil and natural gas companies.

We perform our goodwill test annually during the third quarter or more often if circumstances require. Our goodwill impairment reviews consists of a two-step process. The first step is to determine the fair value of our reporting units and compare it to the carrying value of the related net assets. Fair value is determined based on our estimates of market values. If this fair value exceeds the carrying value no further analysis or goodwill write-down is required. The second step is required if the fair value of the reporting units is less than the carrying value of the net assets. In this step the implied fair value of the reporting units is allocated to all the underlying assets and liabilities, including both recognized and unrecognized tangible and intangible assets, based on their fair values. If necessary, goodwill is then written-down to its implied fair value. If the fair value of the reporting units is less than the book value (including goodwill), then goodwill is reduced to its implied fair value and the amount of the write down is charged against earnings. The assumptions we used in calculating our reporting unit fair values at the time of the test include our market capitalization and discounted future cash flows based on estimated reserves and production, future costs and future oil and natural gas prices. Material adverse changes to any of these factors could lead to an impairment of all or a portion of our goodwill in future periods.

Income Taxes

Our provision for taxes includes both state and federal taxes. We account for income taxes using the asset and liability method wherein deferred tax assets and liabilities are recognized for the future tax consequences attributable to differences between financial statement carrying amounts of existing assets and liabilities and their respective tax bases. Deferred tax assets and liabilities are measured using enacted tax rates expected to apply to taxable income in the years in which temporary differences are expected to be recovered or settled. Deferred tax assets are reduced by a valuation allowance if, based on the weight of available evidence, it is more likely than not that some portion or all of the deferred tax assets will not be realized.

We follow ASC 740, *Income Taxes*, (ASC 740). ASC 740 creates a single model to address accounting for the uncertainty in income tax positions and prescribes a minimum recognition threshold a tax position must meet before recognition in the financial statements. We apply significant judgment in evaluating our tax positions and estimating our provision for income taxes. During the ordinary course of business, there are many transactions and calculations for which the ultimate tax determination is uncertain. The actual outcome of these future tax consequences could differ significantly from these estimates, which could impact our financial position, results of operations and cash flows. The evaluation of a tax position in accordance with ASC 740 is a two-step process. The first step is a recognition process to determine whether it is more likely than not that a tax position will be sustained upon examination, including resolution of any related appeals or litigation processes, based on the technical merits of the position. In evaluating whether a tax position has met the more likely than not recognition threshold, it is presumed that the position will be examined by the appropriate taxing authority with full knowledge of all relevant information. The second step is a measurement process whereby a tax position that meets the more likely than not recognition threshold is calculated to determine the amount of benefit/expense to recognize in the financial statements. The tax position is measured at the largest amount of benefit/expense that is more likely than not of being realized upon ultimate settlement.

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Comparison of Results of Operations

Year Ended December 31, 2010 Compared to Year Ended December 31, 2009

We reported income from continuing operations, net of income taxes, of $234.7 million for the year ended December 31, 2010 compared to a loss from continuing operations, net of income taxes, of $1.0 billion for the comparable period in 2009. The following table summarizes key items of comparison and their related change for the periods indicated.

	Years Ended December 31,		
In thousands (except per unit and per Mcfe amounts)	**2010**	**2009**	**Change**
Income (loss) from continuing operations, net of income taxes	$ 234,652	$ (1,022,329)	$ 1,256,981
Operating revenues:			
Oil and natural gas	1,107,401	732,137	375,264
Marketing	475,030	320,121	154,909
Midstream	15,425	18,418	(2,993)
Operating expenses:			
Marketing	521,378	316,987	204,391
Production:			
Lease operating	64,744	78,700	(13,956)
Workover and other	18,119	2,749	15,370
Taxes other than income	9,171	57,360	(48,189)
Gathering, transportation and other:			
Oil and natural gas	149,735	69,287	80,448
Midstream	11,302	10,695	607
General and administrative:			
General and administrative	130,672	96,551	34,121
Stock-based compensation	23,229	14,458	8,771
Depletion, depreciation and amortization:			
Depletion Full cost	445,094	380,003	65,091
Depreciation Midstream	4,869	7,398	(2,529)
Depreciation Other	5,054	2,761	2,293
Accretion expense	1,979	1,447	532
Full cost ceiling impairment		1,838,444	(1,838,444)
Amortization of deferred gain	155,234		155,234
Other income (expenses):			
Net gain on derivative contracts	301,121	260,248	40,873
Interest expense and other	(295,773)	(229,419)	(66,354)
Equity investment income	17,154		17,154
Income (loss) from continuing operations before income taxes:			
Oil and natural gas	194,268	(1,793,070)	1,987,338
Midstream	195,978	17,735	178,243
Income tax (provision) benefit	(155,594)	753,006	(908,600)
Production:			
Natural gas Mmcf	234,538	172,296	62,242
Crude oil MBbl	1,268	1,520	(252)
Natural gas liquids MBbl	681	290	391
Natural gas equivalent Mmcfe[1]	246,232	183,156	63,076
Average daily production Mmcfe[1]	675	502	173
Average price per unit[2]:			
Natural gas price Mcf	$ 4.18	$ 3.69	$ 0.49
Crude oil price Bbl	76.98	56.15	20.83
Natural gas liquids price Bbl	38.03	28.20	9.83
Natural gas equivalent price Mcfe[1]	4.49	3.99	0.50
Average cost per Mcfe:			
Production:			
Lease operating	0.26	0.43	(0.17)
Workover and other	0.07	0.02	0.05
Taxes other than income	0.04	0.31	(0.27)
Gathering, transportation and other:			
Oil and natural gas	0.61	0.38	0.23
Midstream	0.05	0.06	(0.01)
General and administrative:			
General and administrative	0.53	0.53	
Stock-based compensation	0.09	0.08	0.01

Depletion	1.81	2.07	(0.26)

(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 year ended December 31, 2010, oil and natural gas revenues increased $375.3 million from the same period in 2009, to $1.1 billion. The increase was primarily due to the increase in our production of 63,076 Mmcfe, or 34% over 2009, primarily due to our drilling successes in resource plays in Louisiana, Arkansas and Texas. Increased production contributed to approximately $252 million in revenues for the year ended December 31, 2010. Also contributing to this increase was an increase of $0.50 per Mcfe in our realized average price to $4.49 per Mcfe from $3.99 per Mcfe in the prior year period. The increase per Mcfe led to an increase in oil and natural gas revenues of $123 million.

We had marketing revenues of $475.0 million and marketing expenses of $521.4 million in 2010, resulting in a loss before taxes of $46.4 million as compared to income before taxes of $3.1 million for the same period in 2009. Our marketing subsidiary purchases and sells our own and 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 loss before taxes for the year ended December 31, 2010 is primarily attributable to decreased margins and the inclusion of a full year of amortization of our acquired transportation contracts during the third quarter of 2009.

We had gross revenues from our midstream segment of $54.2 million for year ended December 31, 2010 compared to the same period in 2009 of $63.3 million, a decrease of $9.1 million. Gross revenues of $54.2 million included $38.8 million of inter-segment revenues that were eliminated in consolidation. On a net basis, we had revenues of $15.4 million for the year ended December 31, 2010, a decrease of $3.0 million from the prior year. Gathering and treating throughput decreased 12.5 Bcf to 96.1 Bcf for the year ended December 31, 2010 compared to 108.6 Bcf for the year ended December 31, 2009. 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 and additional gathering and treating revenue from the increased volumes as we continue to develop our gathering and treating system in the Eagle Ford Shale.

Lease operating expenses decreased $14.0 million for the year ended December 31, 2010 as compared to the same period in 2009. The decrease was 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 $0.17 per Mcfe to $0.26 per Mcfe in 2010 from $0.43 per Mcfe in 2009. The decrease on a per unit basis is primarily due to the increase in production during 2010 from our resource plays which historically 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 year ended December 31, 2010 over the same period in 2009 as these properties historically operated with higher operating costs per unit.

Workover expenses increased $15.4 million for the year ended December 31, 2010 compared to the same period in 2009. The increase was primarily due to an increase in activity in the Haynesville Shale related to the replacement of corroded conventional tubing with chrome tubing in a number of our wells.

Taxes other than income decreased $48.2 million for the year ended December 31, 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 decrease is primarily due to severance tax refunds related to drilling incentives for horizontal wells in the Haynesville Shale in Louisiana and, to a

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lesser extent, in Texas and Oklahoma. For the year ended December 31, 2010, we recorded severance tax refunds totaling $47.7 million compared to $3.6 million in refunds for the year ended December 31, 2009. On a per unit basis, excluding the severance tax refunds, taxes other than income decreased $0.10 per Mcfe to $0.23 per Mcfe compared to $0.33 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 $80.4 million, for the year ended December 31, 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 $0.23 per Mcfe to $0.61 per Mcfe in 2010 compared to $0.38 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 increased $0.6 million for the year ended December 31, 2010 compared to the same period in 2009. The increase was primarily due to the expansion of our Eagle Ford gas gathering and treating system 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 year ended December 31, 2010 increased $34.1 million as compared to the same period in 2009. In 2010, we had a $7.9 million increase in professional fees, including $4.3 million for the implementation of new software systems, as well as increases in legal fees and settlements. The closing of our joint venture with Kinder Morgan also contributed to the increase. In conjunction with the formation of KinderHawk, we paid $7.5 million for services to our advisors on the transaction. The remaining increase of $18.7 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.

Stock-based compensation increased $8.8 million for the year ended December 31, 2010 as compared to the same period in the prior year. This increase was primarily due to the increase in our overall employee headcount as we have gone from 469 full time employees as of December 31, 2009 to 598 employees as of December 31, 2010. In addition, the weighted average value per option granted in 2009 was $7.30, which increased to $10.20 in 2010.

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 volumes for the current period to total remaining reserve volumes for the evaluated properties. Depletion expense increased $65.1 million for the year ended December 31, 2010 from the same period in 2009, to $445.1 million. On a per unit basis, depletion expense decreased $0.26 per Mcfe to $1.81 per Mcfe. This decrease on a per unit basis is primarily due to the ceiling test impairment write down of $1.8 billion before taxes for the year ended December 31, 2009.

Depreciation expense associated with our gas gathering systems decreased $2.5 million to $4.9 million for the year ended December 31, 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 Shale gas gathering and treating system. We depreciate our gas gathering systems over a 30 year useful life commencing on the estimated placed in service date.

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. We recorded a full cost ceiling test impairment of approximately $1.8 billion for the year ended December 31, 2009. 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. Accordingly, at March 31, 2009, our costs exceeded our ceiling limitation by approximately $1.7 billion, resulting in an approximate $1.7 billion write down of our oil and natural gas properties. At December 31, 2009, our net book value of oil and gas properties exceeded the ceiling amount based on the unweighted arithmetic average of the first day of each month for the 12-month period end December 31, 2009 WTI posted price of $57.65 per barrel and Henry Hub price of $3.87 per Mmbtu. As a result, we recorded a full cost ceiling test impairment before income taxes of approximately $106 million and $65 million after 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 $917 million in cash. At May 21, 2010, as a result of this transaction, we recorded a deferred gain of approximately $719.4 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 as contributions to KinderHawk are made or upon expiration of the capital commitment at December 31, 2011. In addition to the capital commitment, we guaranteed to deliver certain minimum volumes of natural gas through the Haynesville Shale gathering system through May 2015. We will recognize the remaining deferred gain as volumes are delivered through the Haynesville Shale gathering system through May 2015. During the year ended December 31, 2010, we recognized $155.2 million of the deferred gain.

We enter into derivative commodity instruments to economically hedge our exposure to price fluctuations on our anticipated oil, natural gas, and natural gas liquids 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 consolidated statements of operations. At December 31, 2010, we had a $258.7 million derivative asset, $217.0 million of which was classified as current, and a $19.4 million derivative liability, $5.8 million of which was classified as current. We recorded a net derivative gain of $301.1 million ($58.1 million net unrealized gain and $243.0 million net gain for cash received on settled contracts) for the year ended December 31, 2010 compared to a net derivative gain of $260.2 million ($120.4 million net unrealized loss and a $380.6 million gain for cash received on settled contracts) in the same period in 2009.

Interest expense and other increased $66.4 million for year ended December 31, 2010. This increase was primarily due to the early repurchase of the 2013 Notes in which we incurred charges of approximately $47 million in 2010. Also contributing to the increase was the increased utilization of our Senior Credit Agreement and an overall decrease in capitalized interest as a result of the contribution of our Haynesville gas gathering system to KinderHawk in 2010.

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 consolidated statements of operations. For the year ended December 31, 2010, our net share of KinderHawk's income was $17.2 million.

We had an income tax provision of $155.6 million for the year ended December 31, 2010 due to our income from continuing operations before income taxes of $390.2 million compared to an income tax benefit of $753.0 million due to our loss from continuing operations before income taxes of $1.8 billion in the prior year. The effective tax rate for the year ended December 31, 2010 was 39.9% compared to 42.4% for the year ended December 31, 2009. The change in the effective tax rate is primarily due to changes in estimates of tax benefits associated with amended tax filings in 2009 and a reduction in the state tax rate.

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Year Ended December 31, 2009 Compared to Year Ended December 31, 2008

We reported a loss from continuing operations, net of income taxes, of $1.0 billion for the year ended December 31, 2009 compared to a loss from continuing operations, net of income taxes, of $386.9 million for the comparable period in 2008. The following table summarizes key items of comparison and their related change for the periods indicated.

In thousands (except per unit and per Mcfe amounts)	**Years Ended December 31, 2009**	**2008**	**Change**
Loss from continuing operations, net of income taxes	$ (1,022,329)	$ (386,867)	$ (635,462)
Operating revenues:			
Oil and natural gas	732,137	1,025,995	(293,858)
Marketing	320,121	63,553	256,568
Midstream	18,418	1,316	17,102
Operating expenses:			
Marketing	316,987	58,581	258,406
Production:			
Lease operating	78,700	52,462	26,238
Workover and other	2,749	5,624	(2,875)
Taxes other than income	57,360	47,104	10,256
Gathering, transportation and other:			
Oil and natural gas	69,287	43,012	26,275
Midstream	10,695	140	10,555
General and administrative:			
General and administrative	96,551	61,703	34,848
Stock-based compensation	14,458	12,310	2,148
Depletion, depreciation and amortization:			
Depletion Full cost	380,003	391,042	(11,039)
Depreciation Midstream	7,398	586	6,812
Depreciation Other	2,761	2,342	419
Accretion expense	1,447	1,246	201
Full cost ceiling impairment	1,838,444	950,799	887,645
Other income (expenses):			
Net gain on derivative contracts	260,248	156,870	103,378
Interest expense and other	(229,419)	(151,825)	(77,594)
(Loss) income from continuing operations before income taxes:			
Oil and natural gas	(1,793,070)	(527,856)	(1,265,214)
Midstream	17,735	(3,186)	20,921
Income tax benefit	753,006	144,175	608,831
Production:			
Natural gas Mmcf	172,296	100,143	72,153
Crude oil MBbl	1,520	1,554	(34)
Natural gas liquids MBbl	290	355	(65)
Natural gas equivalent Mmcfe[(1)]	183,156	111,597	71,559
Daily production Mmcfe[(1)]	502	305	197
Average price per unit[(2)]:			
Natural gas price Mcf	$ 3.69	$ 8.54	$ (4.85)
Crude oil price Bbl	56.15	95.16	(39.01)
Natural gas liquids price Bbl	28.20	56.63	(28.43)
Equivalent Mcfe[(1)]	3.99	9.17	(5.18)
Average cost per Mcfe:			
Production:			
Lease operating	0.43	0.47	(0.04)
Workover and other	0.02	0.05	(0.03)
Taxes other than income	0.31	0.42	(0.11)
Gathering, transportation and other:			
Oil and natural gas	0.38	0.39	(0.01)
Midstream	0.06		0.06
General and administrative:			
General and administrative	0.53	0.55	(0.02)
Stock-based compensation	0.08	0.11	(0.03)
Depletion	2.07	3.50	(1.43)

(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 year ended December 31, 2009, oil and natural gas revenues decreased $293.9 million from the same period in 2008, to $732.1 million. The decrease was primarily due to the decrease of $5.18 per Mcfe in our realized average price to $3.99 per Mcfe from $9.17 per Mcfe in the prior year. This decrease per Mcfe led to a decrease in oil and natural gas revenues of $949 million. The effect of lower prices was partially offset by an increase in production of 71,559 Mmcfe or 64% over 2008 due to our continued drilling successes in resource plays in Louisiana, Arkansas and Texas. Increased production contributed approximately $655 million in revenues for the year ended December 31, 2009.

We had marketing revenues of $320.1 million and marketing expenses of $317.0 million in 2009, resulting in income before taxes of $3.1 million. During the fourth quarter of 2008, a subsidiary of ours began purchasing and selling our own and third party natural gas produced from wells 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.

We had gross revenues from our midstream segment of $63.3 million for the year ended December 31, 2009 compared to the same period in 2008 of $1.9 million, an increase of $61.4 million of which $44.3 million represents inter-segment revenues that are eliminated in consolidation. The remaining $17.1 million increase represents gathering and treating revenues from third party owners in our operated wells and revenues associated with third party producers. On a net basis we had revenues of $18.4 million for the year ended December 31, 2009, an increase of $17.1 million from the prior year. The increase in revenues was primarily related to the increase in throughput on our Haynesville gathering systems and treating facilities. Gathering throughput increased 105.3 Bcf to 108.6 Bcf for the year ended December 31, 2009 compared to 3.3 Bcf for the year ended December 31, 2008. The throughput increase resulted from the constructing of 149 miles of gathering pipeline in the Haynesville Shale.

Lease operating expenses increased $26.2 million for the year ended December 31, 2009 as compared to the same period in 2008. This increase was primarily due to our increased production in the current year. On a per unit basis, lease operating expenses decreased $0.04 per Mcfe to $0.43 per Mcfe in 2009 from $0.47 per Mcfe in 2008. This decrease on a per unit basis is primarily due to the increase in production during 2009 from our resource plays which historically have a lower per unit operating cost.

Taxes other than income increased $10.3 million for the year ended December 31, 2009 as compared to the same period in 2008. The increase was primarily due to increased severance taxes resulting from increased production in the current year. Severance taxes are generally assessed as either a fixed rate based on production or as a percentage of gross oil and natural gas sales. On a per unit basis, taxes other than income decreased $0.11 per Mcfe to $0.31 per Mcfe compared to $0.42 per Mcfe in 2008. This decrease on a per unit basis is primarily attributable to the decrease in our realized oil and natural gas prices.

Gathering, transportation and other expense attributable to our oil and natural gas production segment increased $26.3 million for the year ended December 31, 2009 as compared to the same period in 2008. This increase was primarily due to the increase in production discussed above. On a per unit basis, gathering, transportation and other expense decreased $0.01 per Mcfe primarily due to increases in production in our Haynesville Shale play, which generally has lower costs.

Gathering, transportation and other expenses attributable to our midstream segment increased $10.6 million for the year ended December 31, 2009 compared to the same period in 2008. This increase was primarily due to the increase in throughput associated with the continued development of our gathering systems and treating facilities in the Haynesville Shale.

General and administrative expense for the year ended December 31, 2009 increased $34.9 million to $96.6 million compared to $61.7 million in the same period 2008. This increase is primarily attributable to our recent growth. Payroll and benefits increased $10.4 million. Office expense, other professional services, and other increased $1.3 million, $1.9 million, and $3.0 million respectively. Our legal expense increased $17.8 million to accrue for settlements and an additional $2.2 million in legal fees associated with the settlements.

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 volumes for the current period to total remaining reserve volumes for the evaluated properties. Depletion expense decreased $11.0 million for the year ended December 31, 2009 from the same period in 2008, to $380.0 million. On a per unit basis, depletion expense decreased $1.43 per Mcfe to $2.07 per Mcfe. This decrease on a per unit basis is primarily due to the ceiling test impairment write down of $1.7 billion at March 31, 2009 and $950.8 million at December 31, 2008.

Depreciation expense associated with our gas gathering systems increased $6.8 million to $7.4 million for the year ended December 31, 2009. This increase was primarily due to the construction of our gas gathering systems and treating facilities of which we spent $247 million in the Haynesville and Eagle Ford Shales. We depreciate our gas gathering systems over a 30 year useful life and begin depreciating on the estimated placed in service date.

We recorded a full cost ceiling test impairment of approximately $1.8 billion for the year ended December 31, 2009. 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. Accordingly, at March 31, 2009, our costs exceeded our ceiling limitation by approximately $1.7 billion, resulting in an approximate $1.7 billion write down of our oil and natural gas properties. At December 31, 2009, our net book value of oil and gas properties exceeded the ceiling amount based on the unweighted arithmetic average of the first day of each month for the 12-month period end December 31, 2009 WTI posted price of $57.65 per barrel and Henry Hub price of $3.87 per Mmbtu. As a result, we recorded a full cost ceiling test impairment before income taxes of approximately $106 million and $65 million after taxes.

We enter into derivative commodity instruments to economically hedge our exposure to price fluctuations on our anticipated oil and natural gas production. Consistent with the prior year, we have elected not to designate any positions as cash flow hedges for accounting purposes, and accordingly, we recorded the net change in the mark-to-market value of these derivative contracts in the consolidated statement of operations. At December 31, 2009, we had a $162.9 million derivative asset, $112.4 million of which was classified as current and we had a $1.8 million derivative liability, all of which was classified as current. We recorded a net derivative gain of $260.2 million ($120.4 million net unrealized loss and $380.6 million net gain for cash received on settled contracts) for the year ended December 31, 2009 compared to a net derivative gain of $156.9 million ($230.6 million net unrealized gain and $73.7 million net loss for cash paid on settled contracts) in the prior year.

Interest expense and other was $229.4 million and $151.8 million for the years ended December 31, 2009 and 2008, respectively, increasing $77.6 million from the same period in 2008. Interest expense increased $84.0 million due to the issuance of new long-term debt ($25.5 million for

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the $800 million 7.875% senior notes due 2015 and $58.5 million for the $600 million 10.5% senior notes due 2014). In conjunction with the new notes, amortization of debt issuance costs and amortization of the discount recorded on the 2014 Notes accounted for $10.8 million. This was partially offset by a $14.4 million reduction in interest expense associated with the decrease in our outstanding balance on our Senior Credit Agreement compared to the prior year. For the year ended 2009, interest expense included a $5.9 million reduction for the capitalization of the interest associated with the ongoing construction of our gas gathering systems. In addition, we withdrew the proposed public offering of master limited partnership units during 2008 and expensed the related costs of $3.4 million. Due to our utilization of marketable securities and miscellaneous items, interest income decreased $6.7 million.

Income tax benefit for the year ended December 31, 2009 increased $608.8 million from the prior year. The increase in our income tax benefit from the prior year was primarily due to our loss from continuing operations before income taxes of $1.8 billion for the year ended December 31, 2009 compared to our loss from continuing operations before income taxes of $531.0 million in 2008. The effective tax rates for the years ended December 31, 2009 and 2008 were 42.4% and 27.1%, respectively. The change in the effective tax rate from the prior year is primarily due to the benefit generated by the pre-tax loss and changes in estimates of tax benefits associated with amended tax filings.

Related Party Transactions

None.

Recently Issued Accounting Pronouncements

We discuss recently adopted and issued accounting standards in Item 8. *Consolidated Financial Statements and Supplementary Data* Note 1, "*Summary of Significant Events and Accounting Policies*."

ITEM 7A. 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, natural gas, and natural gas liquids prices decline significantly our ability to finance our capital budget and operations could be adversely impacted. We expect energy prices to remain volatile and unpredictable, therefore we have designed a risk management policy which provides for the use of derivative instruments to provide partial protection against declines in oil and natural gas prices by reducing the risk of price volatility and the affect it could have on our operations. The types of derivative instruments that we typically utilize include collars, swaps, and puts. The total volumes which we hedge through the use of our derivative instruments varies from period to period, however, generally our objective is to hedge approximately 65% to 70% of our current and anticipated production 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 8. *Consolidated Financial Statements and Supplementary Data* Note 8,*"Derivatives and Hedging Activities"* for additional information.

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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 December 31, 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 8. *Consolidated Financial Statements and Supplementary Data* Note 8,*"Derivatives and Hedging Activities"* for more details.

Fair Market Value of Financial Instruments

The estimated fair values for financial instruments under ASC 825, *Financial Instruments*, (ASC 825) are 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, cash equivalents, accounts receivable and accounts payable approximates their carrying value due to their short-term nature. See Item 8. *Consolidated Financial Statements and Supplementary Data* Note 5, "*Fair Value Measurements"* for additional information.

Interest Sensitivity

We are also 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 December 31, 2010, total debt was $2.6 billion, of which approximately 94% bears interest at a weighted average fixed interest rate of 8.2% per year. The remaining 6% of our total debt balance at December 31, 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 December 31, 2010, the interest rate on our variable rate debt was 2.5% per year. If the balance of our variable rate debt at December 31, 2010 were to remain constant, a 10% change in market interest rates would impact our cash flow by approximately $0.1 million per quarter.

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ITEM 8. CONSOLIDATED FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

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MANAGEMENT'S REPORT ON INTERNAL CONTROL OVER FINANCIAL REPORTING

Management of Petrohawk Energy Corporation (the Company), including the Company's Chief Executive Officer and Chief Financial Officer, is responsible for establishing and maintaining adequate internal control over financial reporting for the Company. The Company's internal control system was designed to provide reasonable assurance to the Company's Management and Board of Directors regarding the preparation and fair presentation of published financial statements. Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

Management conducted an evaluation of the effectiveness of internal control over financial reporting based on the *Internal Control Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission. Based on this evaluation, management concluded that Petrohawk Energy Corporation's internal control over financial reporting was effective as of December 31, 2010.

Deloitte & Touche LLP, the Company's independent registered public accounting firm, has issued an attestation report on the effectiveness on the Company's internal control over financial reporting as of December 31, 2010 which is included in Item 8. *Consolidated Financial Statements and Supplementary Data*.

/s/ FLOYD C. WILSON	/s/ MARK J. MIZE
Floyd C. Wilson **Chairman of the Board** **and Chief Executive Officer**	**Mark J. Mize** **Executive Vice President,** **Chief Financial Officer and Treasurer**

Houston, Texas
February 21, 2011

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REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Stockholders of
Petrohawk Energy Corporation
Houston, Texas

We have audited the accompanying consolidated balance sheets of Petrohawk Energy Corporation and subsidiaries (the "Company") as of December 31, 2010 and 2009, and the related consolidated statements of operations, stockholders' equity, and cash flows for each of the three years in the period ended December 31, 2010. We also have audited the Company's internal control over financial reporting as of December 31, 2010, based on criteria established in *Internal Control Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission. The Company's management is responsible for these financial statements, for maintaining effective internal control over financial reporting, and for its assessment of the effectiveness of internal control over financial reporting, included in the accompanying Management's Repor