PETROHAWK ENERGY CORP
Form 10-K/A
June 04, 2007
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UNITED STATES

SECURITIES AND EXCHANGE COMMISSION

WASHINGTON, D.C. 20549

FORM 10-K/A

(Amendment No. 2)

ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF

THE SECURITIES EXCHANGE ACT OF 1934

For the fiscal year ended December 31, 2006

Commission file number 000-25717

PETROHAWK ENERGY CORPORATION

(Exact name of registrant as specified in its charter)

Delaware	**86-0876964**
(State or other jurisdiction of incorporation or organization)	**(I.R.S. Employer Identification Number)**

1000 Louisiana, Suite 5600, Houston, Texas 77002

(Address of principal executive offices including ZIP code)

(832) 204-2700

(Registrant s telephone number)

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

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

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

Indicate by check mark whether the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act. Yes x No ¨

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 ¨ No x

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

Indicate by check mark 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. ¨

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

Large accelerated filer x Accelerated filer ¨ Non-accelerated filer ¨

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

The aggregate market value of Common Stock, par value $.001 per share (Common Stock), held by non-affiliates (based upon the closing sales price on the NASDAQ Global Select Market on June 30, 2006), the last business day of registrant s most recently completed second fiscal quarter was approximately $973 million.

As of February 23, 2007, there were 168,536,049 shares of Common Stock outstanding.

DOCUMENTS INCORPORATED BY REFERENCE

None

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EXPLANATORY NOTE

Petrohawk Energy Corporation (hereinafter referred to as Petrohawk, the Company, we, us, or our) is filing this Amendment No. 2 on Form 10-K/A (this Amendment No. 2) to its Annual Report on Form 10-K for the fiscal year ended December 31, 2006, originally filed with the Securities and Exchange Commission (SEC) on February 28, 2007 (the Original Report).

The purpose of this Amendment is to amend Item 1. *Business* and Item 7. *Management s discussion and analysis of financial condition and results of operations* to include the following additional disclosures (1) reserve and production information for our principal fields within the *Core Operating Regions* section of Item 1. *Business* and (2) additional pricing and production information for natural gas liquids in Item 1. *Business* and Item 7. *Management s discussion and analysis of financial condition and results of operations* in response to comments from the SEC following their review of the Company s Annual Report on Form 10-K for the fiscal year ended December 31, 2006. Further, we have amended Item 8. *Consolidated financial statements and supplementary data* to correct information reported in the Supplemental Oil and Gas Information disclosure. This amended item restates the following tables:

Costs Incurred in Oil and Natural Gas Property Acquisition, Exploration and Development Activities table;

Standardized Measure of Discounted Future Net Cash Flows Relating to Proved Oil and Natural Gas Reserves table; and

Changes in Standardized Measure of Discounted Future Net Cash Flows Relating to Proved Oil and Natural Gas Reserves table.

The Costs Incurred in Oil and Natural Gas Property Acquisition, Exploration and Development Activities table has been restated to combine asset retirement costs with Property acquisition costs, proved and Development costs.

The Standardized Measure of Discounted Future Net Cash Flows Relating to Proved Oil and Natural Gas Reserves table has been restated to correct the amount of future income tax expense recognized and correct the methodology utilized in the discount calculation including consideration of the annual impact of income taxes in future periods.

The Changes in Standardized Measure of Discounted Future Net Cash Flows Relating to Proved Oil and Natural Gas Reserves table has been restated to correct Changes in income taxes, net and add Development costs incurred in addition to line items miscalculated in our Annual Report on Form 10-K for the fiscal year ended December 31, 2006, originally filed on February 28, 2007.

This amendment does not affect the Company s historical results of operations, financial conditions, cash flows, reserves or production for any periods presented. While we are amending only certain portions of Items 1, 7 and 8 of our Form 10-K, for convenience and ease of reference, we are filing the entire text of Parts I and II of Form 10-K. In addition, in accordance with applicable rules promulgated by the SEC, we have included currently dated certifications from our Chief Executive Officer and Chief Financial Officer and currently dated consents from named experts other than as specified above. This Amendment No. 2 does not reflect events occurring after the filing of the original Annual Report or modify or update those disclosures affected by subsequent events. Accordingly, this Amendment No. 2 should be read in conjunction with our filings made with the Securities and Exchange Commission.

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Special note regarding forward-looking statements

This report on Form 10-K contains forward-looking statements within the meaning of the federal securities laws. These forward-looking statements may include, among others, statements reflecting the following:

- our growth strategies;
- anticipated trends in our business;
- our future results of operations;
- our ability to make or integrate acquisitions;
- our liquidity and ability to finance our exploration, acquisition and development activities;
- our ability to successfully and economically explore for and develop oil and natural gas resources;
- market conditions in the oil and natural gas industry;
- the impact of government regulation;
- planned capital expenditures;
- increases in oil and natural gas production;
- our financial position, business strategy and other plans and objectives for future operations;
- reserve and production estimates;
- future financial performance; and
- other matters that are discussed in our filings with the United States Securities and Exchange Commission (SEC).

We identify forward-looking statements by use of terms such as expect, anticipate, estimate, plan, believe, intend, will, continue, should, could and similar words and expressions, although some forward-looking statements may be expressed differently. You should be aware that our actual results could differ materially from those contained in the forward-looking statements. You 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 set forth in the forward-looking statements, and the following factors:

the possibility that the industry may be subject to future regulatory or legislative actions (including any additional taxes);

the volatility in commodity prices, supply of, and demand for, oil and natural gas;

risks associated with derivative positions;

the difficulty of estimating the presence or recoverability of oil and natural gas reserves and the future production rates and associated costs;

the need for us to continually replace oil and natural gas reserves;

environmental risks;

drilling and operating risks and expense cost escalations;

exploration and development risks;

the ability of the our management to execute its plans to meet its goals;

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

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- general economic conditions, whether internationally, nationally or in the regional and local market areas in which we are doing business, may be less favorable than expected;

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

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

All forward-looking statements attributable to us or persons acting on our behalf 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 acquisition, development, production and exploration of oil and natural gas properties located onshore in North America. We were formed in June 1997 as a Nevada corporation and were reincorporated in the state of Delaware in July 2004. Our properties are concentrated in East Texas/North Louisiana, onshore Gulf Coast, and in the Permian, Anadarko and Arkoma basins. We have increased our proved reserves and production through acquisitions and the exploitation of acquired properties. In 2006, we acquired approximately 537 billion cubic feet of natural gas equivalent (Bcfe) proved reserves for approximately $2.2 billion primarily in conjunction with our acquisitions in North Louisiana and our merger with KCS Energy, Inc. (KCS). In addition, we sold an estimated 80 Bcfe of proved reserves for approximately $200 million.

During 2006, excluding acquisitions, we replaced approximately 402% of our production organically. Organic reserve additions were primarily driven by drilling tight sand natural gas wells in North Louisiana and 3-D seismic supported exploration drilling in the onshore Gulf Coast region. Fields that contributed significantly to the additions included Elm Grove/Caspiana (Bossier and Caddo Parishes, Louisiana); Terryville (Lincoln Parish, Louisiana); Lions (Goliad County, Texas); Nabors (Starr County, Texas); Jalmat (Lea County, New Mexico) and W.E. Colson (Brooks County, Texas). Following the acquisition of KCS in July 2006, we focused on an active drilling program. We participated in the drilling of 330 and 146 wells in 2006 and 2005, of which 20 and nine were dry holes, for a success rate of 94% in 2006 and 2005.

At December 31, 2006, our estimated total proved oil and natural gas reserves were approximately 1,076 Bcfe, consisting of 31 million barrels of oil (MMBbl) of oil, condensate and natural gas liquids, and 889 billion cubic feet (Bcf) of natural gas. Approximately 63% of our proved reserves were classified as proved developed.

We focus on maintaining a balanced, geographically diverse portfolio of long-lived, lower risk reserves along with shorter lived, higher margin reserves. We believe that this balanced reserve mix provides a diversified cash flow foundation to fund our development and exploration drilling program. We believe the steps taken during 2006, along with our multi-year drilling prospect inventory, position us to increase production and grow reserves in 2007 and beyond.

Recent Developments

We have recently completed several transactions:

Acquisitions

KCS Energy, Inc.

On April 21, 2006, we announced that we had entered into a definitive agreement to merge with KCS. The merger was consummated on July 12, 2006 and was consistent with our goal of acquiring properties within our core operating areas that have a significant proved reserve component and which we believe have additional development and exploration opportunities.

Upon the closing of the merger, KCS stockholders became entitled to receive a combination of $9.00 cash and 1.65 shares of our common stock for each share of KCS common stock. Total consideration for KCS consisted of approximately $1.1 billion of our common stock, approximately $450 million of cash and the assumption of $275 million of KCS debt. In addition, all outstanding options to purchase KCS common stock and restricted shares of KCS common stock were converted into options to purchase our common stock or restricted shares of our common stock using an exchange ratio of approximately 2.3706 shares of our common stock to one share of KCS common stock.

In conjunction with our merger with KCS, we consummated a private placement of $650 million of 9 $^{1}/8$% senior notes which we applied a portion of the net proceeds to fund the cash paid by us to the KCS stockholders.

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In addition, we amended our senior revolving credit facility agreement and we repaid our second lien term loan facility. See the section entitled *Contractual Obligations* under Item 7. *Management s Discussion and Analysis of Financial Condition and Results of Operations* for more details.

The North Louisiana Acquisitions

On January 27, 2006, we completed the acquisition of all of the issued and outstanding common stock of Winwell Resources, Inc. (Winwell). Total consideration for Winwell was approximately $208 million in cash after certain closing adjustments. Also on January 27, 2006, we completed an acquisition of assets from Redley Company (Redley). Total consideration for the assets was approximately $86 million in cash after certain closing adjustments. In the Winwell and Redley transactions (referred to as the North Louisiana Acquisitions), we acquired natural gas properties in the Elm Grove and Caspiana fields in North Louisiana.

Divestitures

Michigan, Wyoming and California

During the fourth quarter of 2006 we sold certain of our oil and natural gas assets in Michigan, Wyoming and California with total estimated proved reserves of approximately 49 Bcfe. The majority of these assets were acquired in our merger with KCS. Our proceeds from these three separate transactions were approximately $135 million, before adjustments, and were recorded as a decrease to our full cost pool.

Gulf of Mexico

On March 21, 2006, we completed the sale of substantially all of our Gulf of Mexico properties for $52.5 million ($43.2 million after certain closing adjustments). These proceeds were recorded as a decrease to our full cost pool.

Business Strategy

Our primary objective is to increase stockholder value. To accomplish this objective, our business strategy is focused on the following:

- ***Pursuit of Strategic Acquisitions***. We continually review opportunities to acquire properties, leasehold acreage and drilling prospects that are complementary to our existing properties. We seek negotiated transactions to acquire operational control of properties that we believe have significant exploitation and exploration potential. Our strategy includes a significant focus on increasing our holdings in fields and basins in which we already own an interest.

- ***Exploitation of Existing Properties***. We have a significant inventory of future drilling locations in targeted areas. Generally, these locations range in depth from 5,000 feet to 13,000 feet and we believe offer relatively low risk opportunities to add production and proved reserves. Most of the locations are step-out or extension wells from existing production in resource plays. We also seek to add proved reserves and increase production through the use of advanced technologies, including detailed reservoir engineering analysis, drilling infill and extension wells utilizing sophisticated fracture stimulation techniques and selectively recompleting existing wells. We believe that many of the properties we have acquired have significant potential and in certain cases have not been actively developed in the past.

- ***Growth Through Exploration***. We conduct an active technology-driven exploration program, primarily in the onshore Gulf Coast region, that is designed to complement our property acquisition and development drilling activities with moderate to high risk exploration projects that may have greater reserve potential.

- ***Property Portfolio Management***. We continually evaluate our property base to identify opportunities to divest non-core, higher cost or less productive properties with limited development potential. This strategy allows us to focus on a portfolio of core properties with significant potential to increase our proved reserves and production. We also focus on reducing the per unit operating costs associated with our existing properties as evidenced by our lease operating expense reduction from $1.04 per Mcfe in 2005 to $0.73 per Mcfe in 2006.

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Maintenance of Financial Flexibility. We intend to maintain substantial borrowing capacity under our senior revolving credit facility. We believe our internally generated cash flows, our borrowing capacity and access to the capital markets will provide us with the financial flexibility to pursue additional acquisitions of producing properties and leasehold acreage and to execute our drilling program. Another component of our financial management strategy includes the use of hedges to secure product prices for a substantial portion of our expected production.

Benefit from the Transactional Nature of Our Industry. The independent exploration and production industry has been consolidating for a number of years. Our business strategy embraces this trend. We intend to assemble a portfolio of quality proved reserves and drilling opportunities within a core group of operated properties that may potentially be desirable as a strategic acquisition target by larger industry participants.

Oil and Natural Gas Reserves

The December 31, 2006 proved reserve estimates presented in this document were prepared by Netherland, Sewell and Associates, Inc. (Netherland, Sewell). 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*. Our reserves are sensitive to commodity prices and their effect on economic producing rates.

The reserves information in this 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 justify 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.

The following table presents certain information as of December 31, 2006. Oil and natural gas liquids are based on the December 31, 2006 West Texas Intermediate posted price of $57.75 per barrel and are adjusted by lease for quality, transportation fees, and regional price differentials. Gas prices are based on a December 31, 2006 Henry Hub spot market price of $5.63 per MMBtu and are adjusted by lease for energy content, transportation fees, and regional price differentials. All prices are held constant in accordance with SEC guidelines. Shut-in wells currently not capable of production are excluded from the producing well information.

	Mid-Continent	**Gulf Coast**(2)	**Permian Basin**(3)	**Total**
Proved Reserves at Year End (Bcfe)				
Developed	358.9	153.1	161.7	673.7
Undeveloped	303.8	51.0	47.6	402.4
Total	662.7	204.1	209.3	1,076.1
Gross Wells	2,615	971	2,487	6,073
Net Wells (1)	821.3	451.5	825.0	2,097.8

(1) *Net wells represents our working interest share of each well. The term net as used in net production throughout this document refers to amounts that include only acreage or production that is owned by the Company and produced to its interest, less royalties and production due to others.*

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(2) *Included in the Gulf Coast region is approximately 3.8 Bcfe of proved reserves located in federal waters of the Gulf of Mexico.*
(3) *Included in the Permian region is approximately 1.3 Bcfe of proved reserves located in Utah, North Dakota and South Dakota.*

Core Operating Regions

We provide reserves and production information for our principal producing fields in the following regional disclosures.

Mid-Continent Region

In the Mid-Continent region, we concentrate our drilling programs primarily in North Louisiana, East Texas and the Anadarko and Arkoma basins. Our Mid-Continent region operations provide us with a solid base for production and reserve growth. As of December 31, 2006, approximately 62% of our reserves, or 662.7 Bcfe, were located in our Mid-Continent fields. Our production from these fields averaged approximately 160 MMcfe/d in the second half of 2006. We plan to continue to exploit areas within the various basins that require low-risk exploitation wells for additional reservoir drainage. Our exploitation wells are generally infill and extension type wells. During 2006, we drilled 203 wells in this region with a success rate of 97%. In 2007, we plan to drill approximately 360 wells in this region, over half of which are planned in the Elm Grove/Caspiana and Terryville fields. We will also pursue drilling in horizontal plays in East Texas and North Louisiana, the Fayetteville shale, the Woodford shale and various other fields.

Elm Grove/Caspiana Field Our largest field, located primarily in Bossier and Caddo Parishes of North Louisiana, produces from the Hosston and Cotton Valley formations. These zones are composed of low permeability sandstones that require fracture stimulation treatments to produce. In 2006, we consolidated acreage from two significant acquisitions, increasing our acreage position so that we currently own working interests in 99 sections giving us exposure to 63,360 gross unit acres, over 35,000 gross acres and over 24,000 net acres. A section is approximately 640 acres or one square mile. We also own mineral and royalty interests in another twelve sections giving us exposure to another 7,680 gross unit acres and close to 1,000 net acres. In the second half of 2006, these fields contributed approximately 30% of our overall net production. As of December 31, 2006, proved reserves for the Elm Grove/Caspiana field were approximately 457 Bcfe, of which approximately 50% were classified as proved undeveloped and approximately 20% proved developed non-producing.

We have been actively drilling infill and step-out wells at Elm Grove utilizing between four and six operated drilling rigs. During the year, we drilled 92 wells increasing net production to nearly 100 MMcfe/d at year-end. In 2007, we plan to drill approximately 100 operated wells to continue growing production and reserves. In addition, we anticipate that we will participate in an estimated 35 non-operated wells.

We have also been successful in two production advancement initiatives in the Elm Grove/Caspiana field. The first initiative involves the use of coiled tubing to fracture stimulate and commingle the shallower Hosston formation with the existing Lower Cotton Valley formation, increasing the present value of the wells and eliminating additional capital expenditures. To date we have performed over 90 of these procedures successfully. We have also begun testing the economics of down-spacing the Lower Cotton Valley formation to 20 acre spacing. Our pilot program has now included the successful drilling of 19 20-acre spacing wells. In 2007 we plan to continue both programs.

Terryville Field Located in Lincoln Parish, Louisiana, this is our second largest producing field. We have acquired a very significant acreage position and hold working interests in over 100 sections surrounding the core producing area of the field, with over 60,000 gross unit acres and 34,000 net acres. The objective formations in this field include the Cotton Valley and Gray sands. In 2006 we drilled 17 wells increasing net production to approximately 35 MMcfe/d at year end. As of

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December 31, 2006, proved reserves for this field were approximately 84 Bcfe. For 2007, we plan to drill approximately 50 wells, including several extension and exploration wells.

WEHLU Field The West Edmond Hunton Lime Unit, or WEHLU, covers 30,000 gross unit or 29,000 net acres (approximately 47 square miles) primarily in Oklahoma County, Oklahoma. The WEHLU field, originally discovered in 1942, is the largest Hunton Lime formation field in the state of Oklahoma. The field has 38 oil and natural gas wells (36 currently producing approximately 6 MMcfe/d net) with stable production holding the entire unit. We own a 98% working interest and 80% net revenue interest in the majority of the field. Additionally, we have an agreement with a company to jointly develop additional reserves and production in a portion of WEHLU. The area of mutual interest created by the agreement covers 5,680 acres located in the central northwest portion of the field and we own a 40% working interest and 33% net revenue interest in this area. Six successful horizontal wells were drilled in 2006 and we expect to drill seven additional horizontal wells in WEHLU in 2007. As of December 31, 2006, proved reserves for this field were approximately 18 Bcfe.

Fayetteville Shale We have interest in 51,200 gross unit acres or 10,500 net acres, primarily in Van Buren and Pope Counties. We drilled three operated wells and participated in three non-operated wells in 2006 to begin exploitation of our acreage position. At year-end, all of these wells were awaiting completion or pipelines. In 2007, we intend to expand our drilling effort in this area by drilling at least eight operated wells and we anticipate participation in another 12 non-operated wells.

Woodford Shale We have an interest in approximately 41 sections, or over 26,000 gross acres, in the Woodford Shale trends within the Arkoma and Ardmore Basins. Of these 41 sections, approximately 15 are in the Pine Hollow field area. We have six non-operated approved authorizations for expenditures for wells that we expect to be drilled in 2007, and anticipate additional operations to occur. The other 26 sections are located within several prospect areas where we are actively acquiring acreage and expect to initiate drilling operations during 2007.

East Texas Our properties in the East Texas Basin produce primarily from the Cotton Valley, Travis Peak and James Lime formations, which range in depth from approximately 6,500 feet to 10,000 feet. We own significant interests in the South Carthage, North Beckville and Blocker fields in Panola and Harrison Counties, Texas. Our working interest in these fields is between 47% and 100%. We have been actively acquiring acreage in the developing James Lime horizontal play and in the Travis Peak vertical play in Nacogdoches and Shelby Counties, Texas. To date we have acquired over 21,000 net acres in the trend with a 74% working interest. During 2006 we drilled two horizontal James Lime wells and two vertical Travis Peak wells in this trend, and anticipate drilling additional wells in both of these plays in 2007.

Gulf Coast Region

In the Gulf Coast region, we have oil and natural gas operations in south Texas, south Louisiana and the Mississippi salt dome basin. We are actively developing our properties and exploring on-trend acreage for new fields. In south Texas, where we have our most significant acreage position, we predominately explore Wilcox, Frio and Vicksburg aged formations. Production from the Gulf Coast region averaged 101 MMcfe/d during the second half of 2006. During 2006 we drilled 56 wells in this region with an overall success of 85%. In 2007 we plan to drill approximately 75 wells, particularly concentrating on fields where delineation and development of recent discoveries is warranted.

South Texas

Lions Field The Lions field in Goliad County continues to be a primary operational area for us. We drilled four wells during 2006, three of which have been completed and one is awaiting completion. Two fourth quarter wells, the Weise #3 and Dehnert #2, had initial flow rates in excess of 6 MMcfe/d

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and 14 MMcfe/d, respectively. The Weise #4, which we expect to have initial sales in the first quarter of 2007, should also be a high rate well. We own approximately 55% working interest in all three wells. We currently have two rigs drilling in the field, one operated and one non-operated, and expect to drill at least six wells during 2007. Additionally, we finalized the acquisition of a high-density 3-D seismic survey in the fourth quarter of 2006 and are utilizing this improved data volume in our 2007 field development program. As of December 31, 2006, proved reserves for the Lions field were approximately 15 Bcfe. Production in the fourth quarter of 2006 averaged 13 Mmcfe/d.

Austin/Mission Rosario Fields We were active in these neighboring field areas in 2006 with the completion of three wells in the Mission Rosario Field and two wells in the Austin Field. In Mission Rosario, we completed the O Connor Ranch #36 (100% working interest), #37 (50% working interest) and #38 (100% working interest), and are currently drilling the #41 (100% working interest). All of these wells are geopressured Lower Wilcox wells that have had initial production of 1.5 MMcfe/d to 4.0 MMcfe/d. In the Austin field, we completed the Dreier #1 (28% working interest) and Salyer- Sherman #1 (58% working interest) from Lower Wilcox sands and had initial rates of 8.5 MMcfe/d and 7.8 MMcfe/d, respectively. We are also in the process of acquiring a new 3-D seismic survey between these two fields that we anticipate will create additional drilling opportunities in 2007.

La Reforma Field We continue to achieve excellent success with the drilling program in this Lower Vicksburg field in Starr County, Texas where we own a 50% working interest. During 2006 we completed the Guerra D #7 at a rate in excess of 9 MMcfe/d, the Guerra D #6 with initial production of 10 MMcfe/d and are currently drilling the Guerra D #9 in a fault block offsetting the Guerra D #7. We also are in the process of completing the Guerra B #1 in Frio sands at approximately 7,500 feet. In 2007, we anticipate drilling between four to seven additional wells in this field. As of December 31, 2006, proved reserves for the La Reforma field were approximately 16 Bcfe. Production in the fourth quarter of 2006 averaged 7 Mmcfe/d.

Provident City Field In 2006 we finalized the completion of the Garrett #1 and #2 wells (50% working interest) in multiple Lower Wilcox sands, with initial rates of 11 MMcfe/d and 2 MMcfe/d, respectively. Additionally, we have developed several more prospects in this area and anticipate drilling at least two wells in 2007.

Nabors Field We completed two wells in 2006 in this field in Starr County, Texas. The Cleopatra #5 and #7, both 100% working interest wells, were completed in Lower Vicksburg sands at initial production rates in excess of 11 MMcfe/d and 9 MMcfe/d, respectively. In 2007 we anticipate drilling at least two additional development wells and at least two additional exploratory wells in the field area.

South Louisiana

Gueydan Field We have multiple opportunities to expand production in this salt dome field in Vermilion Parish, Louisiana where we have 3,000 net acres. We have recently completed acquisition of new 3-D seismic data that was shot specifically to delineate shallow prospects similar to a well that we completed in early 2005. We anticipate drilling at least three shallow exploratory wells in 2007 to test the prospects we have identified with this 3-D data set. We also are in the final stages of performing a Pre-Stack Depth Migration of a large 3-D data set in order to finalize the interpretation of several deep Frio prospects on the flanks of the dome. Once the re-processing of this data has been completed we anticipate drilling an approximate 16,000 foot Camerina test, and have other Mio-Gyp and Marg Tex prospects identified.

Mississippi Salt Dome Basin

Winchester Prospect We have completed two new field discoveries on prospects in Wayne County, Mississippi. The Board of Education #16-11 and the Clark #4-5 were both completed in the fourth quarter of 2006 in the Smackover at approximately 15,500 feet at rates in excess of 900 barrels of oil

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equivalent per day (BOE/d) and 700 BOE/d, respectively. We also have completed drilling the Board of Education #16-14 as an offset to the #16-11 and anticipate completing it in the first quarter of 2007. We will have two rigs operating in the first half of 2007 to accelerate the development of these field areas. Production from this field was deferred until the end of 2006 due to the need to build a gas pipeline, but we expect significant production growth from this region through 2007.

Permian Basin Region

In the Permian Basin region, our principal properties are in the Waddell Ranch field in Crane County, Texas, the TXL field located in Ector County, Texas, the Sawyer Canyon field in Sutton County, Texas and the Jalmat field in Lea County, New Mexico. These legacy fields have low production declines and we pursue low risk workover and development drilling programs designed to replace production. During the second half of 2006, production from this region averaged 41 MMcfe/d. We drilled 52 wells in this region in 2006 with a 92% success ratio. In 2007 we anticipate drilling 50 to 60 wells.

Waddell Ranch Field This field is located in Crane County, Texas and is our most significant property in the region. The Waddell Ranch Field complex is comprised of over 75,000 gross or 22,100 net acres and is productive from over 15 different reservoirs. The primary production is from the Queen, Grayburg, San Andres, Clearfork, and Ellenburger formations ranging in depth from 3,000 feet to 11,000 feet. We have a working interest in this non-operated field that ranges from 18.5% to 75.2%. During 2006, 22 wells were drilled along with 62 workovers and a similar program is planned for 2007. As of December 31, 2006, proved reserves for the Waddell Ranch field were approximately 62 Bcfe. Production in the fourth quarter of 2006 averaged 8 Mmcfe/d. Approximately 75% of the field production is oil.

Sawyer Canyon Field This field is located in Sutton County, Texas and is the second most significant property in the region. The field encompasses approximately 50 sections and during the past several years there have been drilling programs targeting shallow Canyon sandstone formations. We have a 92% to 100% working interest in most of the areas we are actively drilling. We plan to drill six wells in 2007. As of December 31, 2006, proved reserves for the Sawyer Canyon field were approximately 39 Bcfe. Production in the fourth quarter of 2006 averaged 11 Mmcfe/d.

TXL Field This waterflood is located in Ector County, Texas and is unitized in the Clearfork/Tubb formation at approximately 5,600 feet. We have a 20% working interest and a 25% net revenue interest in this non-operated property. Over 100 additional infill drill sites remain to be drilled in this property which we believe will lead to additional proved reserves as well as upside potential. Twelve wells were drilled in 2006 and 14 wells are planned for 2007. As of December 31, 2006, proved reserves for the TXL field were approximately 25 Bcfe. Production in the fourth quarter of 2006 averaged 3 Mmcfe/d. Approximately 63% of the field production is oil.

Jalmat Field An extensive review of Jalmat Field, located in Lea County, New Mexico, has resulted in the identification of over 45 recompletion/stimulation workovers in the Tansill, Yates and Seven Rivers and significant waterflood potential in the Seven Rivers-Queen zone. Offsetting units have had excellent waterflood results in this same interval. We own a 96% working interest and 83% net revenue interest in this field. In 2006 eight wells were drilled and 17 recompletion workovers were completed and 15 workovers are projected for 2007. As of December 31, 2006, proved reserves for the Jalmat field were approximately 48 Bcfe. Production in the fourth quarter of 2006 averaged 6 Mmcfe/d. Approximately 68% of the field production is oil.

Risk Management

We use hedges to reduce price volatility, help ensure that we have adequate cash flow to fund our capital programs and manage price risks and returns on some of our acquisitions and drilling programs. 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 primarily use oil and natural gas price collars, 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. They 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 and natural gas 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.

We only enter into derivatives arrangements with credit worthy counterparties. These arrangements expose us to the risk of financial loss if our counterparty is unable to satisfy its obligations. 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 generally for a primary term of three to five years. In most cases, the term of our undeveloped leases can be extended by paying delay rentals or by producing reserves that are discovered under those leases.

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

	Years Ended December 31,					
	2006		2005		2004	
	Gross	Net	Gross	Net	Gross	Net
Exploratory Wells:						
Productive [1]	178	71.16	8	2.40	2	0.57
Dry	19	5.99	5	1.29	5	0.42
Total Exploratory	197	77.15	13	3.69	7	0.99
Development Wells:						
Productive [1]	132	59.78	129	27.40	61	10.79
Dry	1	0.02	4	1.35	3	0.15
Total Development	133	59.80	133	28.75	64	10.94
Total Wells:						
Productive [1]	310	130.94	137	29.80	63	11.36
Dry	20	6.01	9	2.64	8	0.57
Total	330	136.95	146	32.44	71	11.93

[1] *Although a well may be classified as productive upon completion, future production may deem the well to be uneconomical, particularly exploratory wells where there is no production history.*

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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 or licenses that have varying terms. The following table presents a summary of our acreage interests as of December 31, 2006:

	Developed Acreage		Undeveloped Acreage		Total Acreage	
	Gross	Net	Gross	Net	Gross	Net
State						
Alabama	1,920	174	27,389	13,695	29,309	13,869
Arkansas	15,881	4,243	127,553	95,453	143,434	99,696
Kansas	16,761	5,512	8,866	3,519	25,627	9,031
Louisiana	165,450	59,467	57,489	49,856	222,939	109,323
Mississippi	16,119	4,402	7,661	2,602	23,780	7,004
New Mexico	27,709	12,658	320	149	28,029	12,807
North Dakota	9,680	795			9,680	795
Oklahoma	271,709	93,688	15,376	8,742	287,085	102,430
South Dakota	1,280	320			1,280	320
Texas	491,377	145,333	125,444	78,268	616,821	223,601
Utah	14,720	1,506			14,720	1,506
Offshore	85,063	10,152			85,063	10,152
Total Acreage	1,117,669	338,250	370,098	252,284	1,487,767	590,534

At December 31, 2006, we had estimated proved reserves of approximately 1,076 Bcfe comprised of 889 Bcf of natural gas and 31 MMBbls of oil, condensate and natural gas liquids located primarily onshore in North America. The following table sets forth, at December 31, 2006, these reserves:

	Proved Developed	Proved Undeveloped	Total Proved
Gas (Bcf)	534.6	354.5	889.1
Oil (MMBbls)	23.2	8.0	31.2
Equivalent (Bcfe)	673.7	402.4	1,076.1

The estimates of quantities of proved reserves above were made in accordance with the definitions contained in SEC Regulation S-X, Rule 4-10(a). For additional information on our oil and natural gas reserves, see Item 8. *Consolidated Financial Statements and Supplementary Data Supplementary Oil and Gas Information.*

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 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.

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Capitalized costs of our evaluated and unevaluated properties at December 31, 2006, 2005 and 2004 are summarized as follows:

	2006	December 31, 2005 (in thousands)	2004
Capitalized costs:			
Evaluated properties	$ 2,901,649	$ 1,096,810	$ 484,233
Unevaluated properties	537,611	162,133	48,840
	3,439,260	1,258,943	533,073
Less accumulated depreciation and depletion	(379,017)	(121,456)	(48,740)
	$ 3,060,243	$ 1,137,487	$ 484,333

Our oil and natural gas production volumes and average sales price are as follows:

	Years Ended December 31, 2006	2005	2004
Production:			
Gas production (MMcf) [(1)]	63,643	20,219	3,569
Oil production (MBbl)	2,703	1,555	244
Equivalent production (MMcfe)	79,863	29,549	5,030
Average Daily Production (MMcfe)	219	81	14
Average price per unit:			
Gas (per Mcf) [(1)]	$ 6.57	$ 8.46	$ 6.53
Oil (per Bbl)	62.27	55.62	40.71
Equivalent (per Mcfe)	7.34	8.73	6.61

(1) *Approximately 5% and 7% of natural gas production represents natural gas liquids (calculated with a 6:1 equivalent ratio) with an average price of $36.88 per Bbl and $40.50 per Bbl for the years ended December 31, 2006 and 2005, respectively. Natural gas liquids represented less than 1% of natural gas production for the year ended December 31, 2004.*

The 2006, 2005 and 2004 average oil and natural gas sales prices above do not reflect the impact of cash paid on settled derivative contracts as these amounts are reflected as other income and expenses in the consolidated statement of operations, consistent with our decision not to elect hedge accounting. Including the impact of cash paid on settled derivative contracts, 2006, 2005 and 2004 realized gas prices were $6.75, $7.32 and $6.41 per Mcf and our realized oil prices were $54.28, $47.20 and $37.76 per Bbl, respectively.

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, locating and obtaining sufficient rig availability, and obtaining purchasers and transporters of the oil and natural gas we produce. 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. 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

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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. The exact effect of these risk factors cannot be accurately predicted.

Other Business Matters

Markets and Major Customers

In 2006 and 2004, we had no individual purchaser that accounted for more than 10% of our total sales. In 2005, we had one individual purchaser that accounted for approximately 12% 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 in the fourth and first quarters resulting in higher natural gas prices. Due to these seasonal fluctuations, results of operations for individual quarterly periods may not be indicative of the results that may be realized 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 circumstances that 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 may occur. In such event, substantial liabilities to third parties or governmental entities may be incurred, the payment 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. We are not aware of any of these instances that have occurred to date that need to be accrued for.

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 and results of operations. For further discussion on risks see Item 7. *Management s Discussion and Analysis of Financial Condition and Results of Operations.*

Regulations

Domestic exploration for, production and sale of, oil and natural gas are extensively regulated at both the federal, state and local levels. Legislation affecting the oil and natural gas industry is under constant review for amendment or expansion, frequently increasing the regulatory burden. Also, numerous departments and agencies, both federal and state, are authorized by statute to issue, and have issued, rules and regulations binding on the oil and natural gas industry that often are costly to comply with and that carry substantial penalties for failure to comply. In addition, production operations are affected by changing tax and other laws relating to the oil and natural gas industry, constantly changing administrative regulations and possible interruptions or termination by government authorities.

State regulatory authorities have established rules and regulations requiring permits for drilling operations, drilling bonds and reports concerning operations. Most states in which we operate also have statutes and regulations governing a number of environmental and conservation matters, including the unitization or pooling of oil and natural gas properties and establishment of maximum rates of production from oil and natural gas wells. Many states also restrict production to the market demand for oil and natural gas. Such statutes and regulations may limit the rate at which oil and natural gas could otherwise be produced from our properties.

We are subject to extensive and evolving environmental laws and regulations. These regulations are administered by the United States Environmental Protection Agency and various other federal, state, and local environmental, zoning, health and safety agencies, many of which periodically examine our operations to monitor compliance with such laws and regulations. These regulations govern the release of waste materials into the environment, or otherwise relating to the protection of the environment, human, animal and plant health, and affect our operations and costs. In recent years, environmental regulations have taken a cradle to grave approach to waste management, regulating and creating liabilities for the waste at its inception to final disposition. Our oil and natural gas exploration, development and production operations are subject to numerous environmental programs, some of which include solid and hazardous waste management, water protection, air emission controls and situs controls affecting wetlands, coastal operations and antiquities.

Environmental 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 request 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 materials.

Each state in which we operate has laws and regulations governing solid waste disposal, water and air pollution. Many states also have regulations governing oil and natural gas exploration, development and production operations.

We are also 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. We believe we are in compliance with these requirements in all material respects.

We may be required in the future to make substantial outlays to comply with environmental laws and regulations. The additional changes in operating procedures and expenditures required to comply with future laws dealing with the protection of the environment cannot be predicted.

Employees

As of December 31, 2006, we had 318 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 Exchange Act of 1934, as amended, or 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 any amendments to such reports available free of charge through our corporate website at *www.petrohawk.com* as soon as reasonably practicable after we file any such report with the SEC. In addition, information related to the following items, among other information, can be found on our website: our press releases, our corporate governance guidelines, our code of conduct, our audit committee charter, our compensation committee charter and our nominating committee charter. 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, the SEC

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maintains an internet site that contains our reports, proxy and information statements, and our other filings which are also available to the public over the internet at the SEC s website at *www.sec.gov*.

ITEM 1A. RISK FACTORS

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 revolving credit facility will be subject to periodic redetermination based in part 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 (OPEC) and other producing countries to agree upon and maintain oil prices and production levels;
- political instability, 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.

In general, the volume of production from oil and natural gas properties declines as reserves are depleted. Our reserves will decline as they are produced unless we acquire properties with proved reserves or conduct successful development and exploration activities. Thus, our future oil and natural gas production and, therefore, our cash flow and income are highly dependent upon our level of success in finding or acquiring additional reserves. However, we cannot assure you that our future acquisition, development and exploration activities will result in any specific amount of additional proved reserves or that we will be able to drill productive wells at acceptable costs.

The successful acquisition of producing properties requires an assessment of a number of factors. These factors include recoverable reserves, future oil and natural gas prices, operating costs and potential environmental and other liabilities, title issues and other factors. Such assessments are inexact and their accuracy is inherently uncertain. In connection with such assessments, we perform a review of the subject properties that we believe is thorough. However, there is no assurance that such a review will reveal all existing or potential problems or allow us to fully assess the deficiencies and capabilities of such properties. We cannot assure you that we will be able to acquire properties at acceptable prices because the competition for producing oil and natural gas properties is particularly intense at this time and many of our competitors have financial and other resources which are substantially greater than those available to us.

Our bank lenders can limit our borrowing capabilities, which may materially impact our operations.

As of December 31, 2006, we had approximately $1.3 billion of long-term debt. As of December 31, 2006, the borrowing base under our senior revolving credit facility was $710 million and we had outstanding borrowings under the facility of $295 million. The borrowing base limitation under our senior revolving credit facility is semi-annually redetermined. Redeterminations are based upon a number of factors, including commodity prices and reserve levels. Upon a redetermination, our borrowing base could be substantially reduced. We utilize cash flow from operations, bank borrowings and debt and equity financings to fund our development, acquisition and exploration activities. A reduction in our borrowing base could limit our activity in this regard. In addition, we may significantly alter our capitalization in order to make future acquisitions or develop our properties. These changes in capitalization may significantly increase our level of debt. If we incur additional debt for these or other purposes, the related risks that we now face could intensify. A higher level of debt also increases the risk that we may default on our debt obligations. Our ability to meet our debt obligations and to reduce our level of debt depends on our future performance which is affected by general economic conditions and financial, business and other factors. Many of these factors are beyond our control. Our level of debt affects our operations in several important ways, including the following:

- a portion of our cash flow from operations is used to pay interest on borrowings;
- the covenants contained in the agreements governing our debt limit our ability to borrow additional funds, pay dividends, dispose of assets or issue shares of preferred stock and otherwise may affect our flexibility in planning for, and reacting to, changes in business conditions;
- a high level of debt may impair our ability to obtain additional financing in the future for working capital, capital expenditures, acquisitions, general corporate or other purposes;
- a more leveraged financial position would make us more vulnerable to economic downturns and could limit our ability to withstand competitive pressures; and
- any debt that we incur under our senior revolving credit facility will be at variable rates which make us vulnerable to increases in interest rates.

Our ability to finance our business activities will require us to generate substantial cash flow.

Our business activities require substantial capital. We have budgeted 2007 drilling expenditures of $575 million. We intend to finance our capital expenditures in the future primarily through cash flow from operations. We cannot be sure that our business will continue to generate cash flow at or above current levels. Future cash flows and the availability of financing will be subject to a number of variables, such as:

- the level of production from existing wells;
- prices of oil and natural gas;

- our results in locating and producing new reserves;
- the success and timing of development of proved undeveloped reserves; and
- general economic, financial, competitive, legislative, regulatory and other factors beyond our control.

If we are unable to generate sufficient cash flow from operations to fund our budgeted drilling expenditures, we may be forced to reduce such expenditures or obtain additional financing through the issuance of debt and/or

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equity. We cannot be sure that any additional financing will be available to us on acceptable terms. Issuing equity securities to satisfy our financing requirements could cause substantial dilution to our existing stockholders. The level of our debt financing could also materially affect our operations.

If our cash flows were to decrease due to lower oil and natural gas prices, decreased production or other reasons, and if we could not obtain capital through our senior revolving credit facility or otherwise, our ability to execute our development and acquisition plans, replace our reserves or maintain production levels could be greatly limited.

Estimates of 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 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, 2006, approximately 37% of our estimated reserves were classified as proved undeveloped. Estimates of proved undeveloped reserves are less certain than estimates of proved developed reserves. 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, we cannot assure you that the estimated costs or estimated reserves are accurate, that development will occur as scheduled or that the actual results will 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

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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.

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 and natural gas production, we have entered into oil and natural gas price hedging arrangements with respect to a portion of our anticipated production. We will most likely enter into additional hedging transactions in the future. While intended to reduce the effects of volatile oil and natural gas prices, such transactions may limit our potential gains and increase our potential losses if oil and natural gas 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 and the delivery point assumed in the hedge arrangement; or
- the counterparties to our hedging agreements fail to perform under the contracts.

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 H_2S 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.

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

Governmental and environmental regulations could adversely affect our business.

Our business is subject to federal, state and local laws and regulations on taxation, the exploration for and development, production and marketing of oil and natural gas and safety matters. Many laws and regulations require drilling permits and govern the spacing of wells, rates of production, prevention of waste, unitization and pooling of properties and other matters. These laws and regulations have increased the costs of planning, designing, drilling, installing, operating and abandoning our oil and natural gas wells and other facilities. In addition, these laws and regulations, and any others that are passed by the jurisdictions where we have production, could limit the total number of wells drilled or the allowable production from successful wells, which could limit our revenues.

Our operations are also subject to complex environmental laws and regulations adopted by the various jurisdictions in which we have or expect to have oil and natural gas operations. We could incur liability to governments or third parties for any unlawful discharge of oil, natural gas or other pollutants into the air, soil or water, including responsibility for remedial costs. We could potentially discharge these materials into the environment in any of the following ways:

- from a well or drilling equipment at a drill site;
- from gathering systems, pipelines, transportation facilities and storage tanks;
- damage to oil and natural gas wells resulting from accidents during normal operations; and
- blowouts, hurricanes, cratering and explosions.

Because the requirements imposed by laws and regulations are frequently changed, we cannot assure you that laws and regulations enacted in the future, including changes to existing laws and regulations, will not adversely affect our business. In addition, because we acquire interests in properties that have been operated in the past by others, we may be liable for environmental damage caused by the former operators.

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;
- 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 and results of operations. 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. A loss in connection with our oil and natural gas properties could have a materially adverse effect on our financial position and results of operations to the extent that the insurance coverage provided under our policies cover only a portion of any such loss.

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. 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 leaseholds. We expect acquisitions will 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 in order 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 all of our prospects will result in viable projects or that we will not abandon our initial investments. Additionally, we cannot guarantee that the leasehold acreage we acquire 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. We rely to a significant extent on 3-D seismic data and other advanced technologies in identifying leasehold acreage prospects and in conducting our exploration activities. The 3-D seismic data and other technologies we use do not allow us to know conclusively prior to our acquisition of leasehold acreage or drilling a well whether oil or gas is present or may be produced economically. The use of 3-D seismic data and other technologies also requires greater pre-drilling expenditures than traditional drilling strategies.

In addition, we may not be successful in controlling and reducing our drilling and production costs in order to improve our overall return. The cost of drilling, completing and operating a well is often uncertain and cost

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factors can adversely affect the economics of a project. We cannot predict the cost of drilling, 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 rigs and the delivery of equipment;
- adverse weather conditions, including hurricanes; and
- compliance with governmental requirements.

The unavailability or high cost of drilling rigs, equipment, supplies, 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 or qualified personnel. 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. As a result of increasing levels of exploration and production in response to strong prices of oil and natural gas, the demand for oilfield services has risen, and the costs of these services are increasing, while the quality of these services may suffer. If the unavailability or high cost of drilling rigs, equipment, supplies or qualified personnel were particularly severe in Texas and Louisiana, we could be materially and adversely affected because our operations and properties are concentrated in those areas. In order to secure drilling rigs in these areas, we have entered into certain contracts with drilling companies that extend over several years. If demand for drilling rigs subsides 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.

The marketability of our oil and natural gas production depends on services and facilities that we typically do not own or control. The failure or inaccessibility of any such services or facilities could result in a curtailment of production and revenues.

The marketability of our production depends in part upon the availability, proximity and capacity of gathering systems, pipelines and processing facilities. Pursuant to interruptible or short term transportation agreements, we generally deliver gas through gathering systems and pipelines that we do not own. Under the interruptible transportation agreements, the transportation of our gas may be interrupted due to capacity constraints on the applicable system, for maintenance or repair of the system, or for other reasons as dictated by the particular agreements. If any of the pipelines or other facilities become unavailable, we would be required to find a suitable alternative to transport and process the gas, which could increase our costs and reduce the revenues we might obtain from the sale of the gas.

We depend on the skill, ability and decisions of third party operators to a significant extent.

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.

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

We may be required under full cost accounting rules to writedown 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

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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 prevailing oil and natural gas prices on the last day of the period or a subsequent higher price under certain limited circumstances. 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 writedown the book value of our oil and natural gas properties. Depending on the magnitude, a ceiling test writedown could significantly reduce income, or produce a loss. As ceiling test computations involve the prevailing oil and natural gas prices, as of a fixed date, it is impossible to predict the likelihood, timing and magnitude of any future impairments. The book value of our proved oil and natural gas properties increased in 2005 and during 2006 as a function of higher acquisition, exploration and development costs. To the extent finding and development costs continue to increase, we will become more susceptible to ceiling test writedowns in lower price environments.

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 including KCS, 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.

Goodwill is not amortized, but instead must be tested at least annually for impairment by applying a fair value based test. Goodwill is deemed impaired to the extent of any excess of its carrying amount over the residual fair value of the business. Such non-cash impairment could significantly reduce earnings during the period in which the impairment occurs, and would result in a corresponding reduction to goodwill and stockholders equity.

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 *6, Commitments and Contingencies,* and is incorporated herein by reference.

ITEM 4. SUBMISSION OF MATTERS TO A VOTE OF SECURITY HOLDERS

No matters were submitted to a vote of our stockholders during the fourth quarter of the fiscal year ended December 31, 2006.

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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 began trading July 16, 2004 on the Nasdaq Stock Market under the symbol HAWK. Prior to July 16, 2004, our common stock traded on the Nasdaq Stock Market under the symbol BETA. The following table sets forth the high and low intra-day sales prices per share of our common stock as reported on the Nasdaq Stock Market.

	High	Low
2006		
First Quarter	$ 16.25	$ 11.75
Second Quarter	14.64	10.01
Third Quarter	13.00	9.76
Fourth Quarter	13.08	9.90
2005		
First Quarter	$ 10.98	$ 7.45
Second Quarter	11.94	7.57
Third Quarter	14.91	10.45
Fourth Quarter	15.17	11.02

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 revolving credit facility and our other long-term debt.

Approximately 687 stockholders of record as of December 31, 2006 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

We did not purchase any of our equity securities during the fourth quarter of 2006. In addition, we did not sell any of our equity securities which were not registered under the Securities Act of 1933, as amended, during the fourth quarter of 2006.

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Five-Year Stock Performance Graph

The following common stock performance graph shows the performance of Petrohawk stock up to December 31, 2006. 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, 2002.

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 NASDAQ Stock Market (U.S.) Index and a peer group index comprised of eight U.S. companies engaged in crude oil and natural gas operations whose stocks were traded on NASDAQ or the NYSE during the period from January 1, 2002 through December 31, 2006. The companies that comprise the peer group are Cabot Oil & Gas, Inc. (COG), Comstock Resources, Inc. (CRK), Cimarex Energy Co. (XEC), Exco Resources, Inc. (XCO), Encore Acquisition Co. (EAC), St. Mary Land & Exploration Co. (SM) Whiting Petroleum Co. (WLL), Forest Oil Corp. (FST), Range Resources Corp. (RRC), and Houston Exploration Co. (THX).

	12/31/2002	12/31/2003	12/31/2004	12/31/2005	12/31/2006
Petrohawk	$ 100.00	$ 229.07	$ 497.67	$ 768.60	$ 668.60
Peer Group	$ 100.00	$ 144.58	$ 232.05	$ 288.25	$ 278.83
Nasdaq Market	$ 100.00	$ 150.01	$ 162.89	$ 165.13	$ 180.85

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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. The acquisition of KCS in 2006, Mission in 2005 and of Wynn-Crosby Energy, Inc. and eight of the limited partnerships it owned (Wynn-Crosby) in 2004 affects the comparability between the consolidated financial data for the periods presented.

	Years ended December 31,				
	2006	2005	2004	2003	2002
	(In thousands, except per share data)				
Income Statement Data:					
Oil and gas sales	$ 587,762	$ 258,039	$ 33,577	$ 12,925	$ 9,648
Income from operations	154,540	103,890	4,699	1,496	(6,347)
Net income (loss)	116,563	(16,634)	8,117	968	(6,882)
Net income (loss) available to common stockholders	116,346	(17,074)	7,672	521	(7,329)
Earnings (loss) per share of common stock: [(1)(3)]					
Basic	$ 0.95	$ (0.31)	$ 0.71	$ 0.08	$ (1.18)
Diluted	$ 0.92	$ (0.31)	$ 0.36	$ 0.08	$ (1.18)
Balance sheet data:					
Working (deficit) capital	$ (85,307)	$ (37,905)	$ 8,856	$ 2,189	$ (77)
Total assets	4,279,656	1,410,174	534,199	46,115	44,753
Total long-term debt [(2)]	1,326,239	495,801	239,500	13,285	13,635
Stockholders equity	1,928,344	526,458	247,091	29,270	28,048

(1) *On May 18, 2004, our Board of Directors approved a one-for-two reverse stock split that was effective May 26, 2004. The reverse stock split was implemented to effect the conditional approval by the NASDAQ National Market of our listing application, which was later formally approved. As a result, all prior year common stock share amounts have been restated to reflect this reverse stock split in the chart above.*

(2) *Amount excludes deferred premiums on derivatives which have been classified as current for all periods presented.*

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

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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 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 acquisition, development, production and exploration of oil and natural gas properties located in onshore North America. Our properties are concentrated in East Texas/North Louisiana, onshore Gulf Coast, and in the Permian, Anadarko and Arkoma basins. We have increased our proved reserves and production through acquisitions and the exploitation of acquired properties. In 2006 we acquired approximately 537 Bcfe of proved reserves for approximately $2.2 billion in conjunction with our acquisitions in North Louisiana and our merger with KCS Energy, Inc. In addition, we sold an estimated 80 Bcfe of proved reserves for approximately $200 million.

During 2006, excluding acquisitions, we replaced approximately 402% of our production organically. Organic reserve additions were primarily driven by drilling tight sand natural gas wells in north Louisiana and 3-D seismic supported exploration drilling in the onshore Gulf Coast region. Fields that contributed significantly to the additions included Elm Grove/Caspiana (Bossier and Caddo Parishes, Louisiana); Terryville (Lincoln Parish, Louisiana); Lions (Goliad County, Texas); Nabors (Starr County, Texas); Jalmat (Lea County, New Mexico) and W.E. Colson (Brooks County, Texas). Following the acquisition of KCS in July 2006, we focused on an active drilling program. We participated in the drilling of 330 and 146 wells in 2006 and 2005, of which 20 and nine were dry holes, for a success rate of 94% in 2006 and 2005.

We focus on maintaining a balanced, geographically diverse portfolio of long-lived, lower risk reserves along with shorter lived, higher margin reserves. We believe that this balanced reserve mix provides a diversified cash flow foundation to fund our development and exploration drilling program. We believe the steps taken during 2006, along with our multi-year drilling prospect inventory, position us to increase production and grow reserves in 2007 and beyond.

Our financial results depend upon many factors, particularly the price of oil and natural gas and our ability to market our production. Commodity prices are affected by changes in market demands, which are impacted by overall economic activity, weather, pipeline capacity constraints, inventory storage levels, basis differentials and other factors. As a result, we cannot accurately predict future oil and natural gas prices, and therefore, we cannot determine the effect increases or decreases in future prices will have on our capital program, production volumes and future revenues. Finding and developing oil and natural gas reserves at economical costs are also critical to our long-term success.

Capital Resources and Liquidity

Our primary sources of cash in 2006 and 2005 were from operating and financing activities. Proceeds from the issuance of long-term debt and cash received from operations as well as divestitures in both years were offset by cash used in investing activities to complete our acquisition activities. Operating cash flow fluctuations were substantially driven by commodity prices and changes in our production volumes. Prices for oil and natural gas have historically been subject to seasonal influences characterized by peak demand and higher prices in the winter heating season; however, the impact of other risks and uncertainties have influenced prices throughout recent years. Working capital was substantially influenced by these variables. Fluctuation in cash flow may result in an increase or decrease in our capital and exploration expenditures. See Results of Operations below for a review of the impact of prices and volumes on sales. Cash flows provided by operating activities were primarily used to fund exploration and development expenditures. See below for additional discussion and analysis of cash flow.

	Years Ended December 31,		
	2006	2005	2004
		(In thousands)	
Net cash provided by operating activities	$ 296,893	$ 135,446	$ 17,943
Net cash used in investing activities	(972,566)	(206,109)	(400,481)
Net cash provided by financing activities	668,355	77,914	386,088
Net (decrease) increase in cash	$ (7,318)	$ 7,251	$ 3,550

Operating Activities. Net cash flows provided by operating activities were $296.9 million, $135.4 and $17.9 million for the years ended December 31, 2006, 2005 and 2004, respectively. Key drivers of net operating cash flows are commodity prices, production volumes and operating costs. Net cash flows provided by operating activities increased in 2006 primarily due to our 170.3% increase in production volumes as a result of our recent acquisition activities as well as our continued drilling success. Also contributing to this increase was our success in reducing our operating costs on a per unit basis as we lowered our lease operating expense to $0.73 per Mcfe in 2006 from $1.04 per Mcfe in 2005. The increase was partially offset by a 15.9% decrease in our realized natural gas equivalent price compared to 2005. We expect 2007 production to increase, but we are unable to predict future commodity prices. As a result, we cannot provide any assurance about future levels of net cash provided by operating activities.

Net cash provided by operating activities in 2005 increased $117.5 million from 2004. This increase was primarily due to higher commodity prices and an increase in sales volumes in conjunction with the closing of our acquisition of Mission in July 2005, as well as our acquisition of Proton Oil and Gas Corporation (Proton) in February 2005 and the inclusion of a full year of production for Wynn-Crosby which we acquired in November 2004. Average realized prices increased $2.12 from $6.61 per Mcfe in 2004 to $8.73 per Mcfe in 2005. Production volumes increased 24,519 MMcfe from 5,030 MMcfe in 2004 to 29,549 MMcfe in 2005.

Net cash provided by operating activities in 2004 increased $12.2 million from 2003. This increase was primarily due to a 38% increase in the average equivalent price per Mcfe as our average realized price increased $1.83 per Mcfe from $4.78 in 2003 to $6.61 in 2004. Also leading to the increase in cash provided by operating activities was an increase in volumes of approximately 2,398 MMcfe that was comprised of a 684 MMcfe increase from drilling and a 1,714 MMcfe increase due to our acquisition of Wynn-Crosby.

Investing Activities. The primary driver of cash used in investing activities was capital spending, inclusive of acquisitions and net of divestitures. Cash used in investing activities was $972.6 million, $206.1 million and $400.5 million for the years ended December 31, 2006, 2005 and 2004, respectively.

Cash used in investing activities in 2006 was $972.6 million. During the fourth quarter of 2006 we sold certain of our oil and natural gas assets in Michigan, Wyoming and California with total estimated reserves of approximately 49 Bcfe. The majority of these assets were acquired in our merger with KCS. Our proceeds from these three separate transactions were approximately $135 million, before adjustments. The net proceeds received in this transaction were used to pay down a portion of our debt facilities

On July 12, 2006, we merged with KCS. Total consideration for the shares of KCS common stock consisted of approximately $1.1 billion of our common stock, approximately $450 million in cash and the assumption of $275 million of KCS debt. In addition, all outstanding options to purchase KCS common stock and restricted shares of KCS common stock were converted into options to purchase our common stock or restricted shares of our common stock using an exchange ratio of approximately 2.3706 shares of our common stock to one share of KCS common stock.

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During the first quarter of 2006, we completed the acquisition of stock of Winwell for $208 million in cash after closing adjustments, and the acquisition of certain oil and natural gas properties for $86 million in cash after closing adjustments. In conjunction with these acquisitions, we deposited a total of $22.5 million in earnest money that was included in other non-current assets at December 31, 2005 and applied to the overall purchase price in January 2006.

We closed the $52.5 million divestment of substantially all of our properties in the Gulf of Mexico on March 21, 2006. The net proceeds received in this transaction were used to pay down a portion of our debt facilities. We received an additional $12.6 million in proceeds from the sale of assets during the third quarter of 2006 primarily related to the sale of a group of non-operated properties.

During 2006, we spent an additional $395.5 million on capital expenditures in conjunction with our drilling program. We participated in the drilling of 330 wells in 2006, of which 20 were dry holes, for a success rate of 94%.

Cash used in investing activities was $206.1 million in 2005. During the third quarter of 2005, we acquired Mission for consideration consisting of approximately $210 million of our common stock and $96.5 million in cash, net of cash acquired. We also assumed $184 million of Mission s long-term debt. During the first quarter of 2005, we completed the acquisition of Proton for $52.6 million in cash.

The 2005 acquisitions were offset by the receipt of $88.9 million in 2005, primarily for the sale of certain royalty properties for approximately $80 million. The remaining portion of this amount is primarily comprised of capital spending and exploration costs of approximately $121 million. In 2005, we drilled 146 gross wells compared to 71 in 2004.

Cash used in investing activities in 2004 was $400.5 million. In November 2004, we acquired Wynn-Crosby for approximately $385 million in cash. Also included in this amount is the addition of certain oil and natural gas properties from PHAWK, LLC which we acquired in May 2004 for approximately $3 million. The remaining portion of this amount is primarily comprised of capital spending and exploration costs of approximately $13 million. In 2004, we drilled 71 gross wells compared to 28 in 2003.

Our 2007 capital budget of $575 million is expected to be funded primarily from cash flows from operations. We establish the budget for these amounts based on our current estimate of future commodity prices, including existing hedges. Due to the volatility of commodity prices, our budget may be periodically adjusted.

Financing Activities. Net cash flows provided by financing activities were $668.4 million, $77.9 million and $386.1 million for the years ended December 31, 2006, 2005 and 2004, respectively. Cash flows provided by financing activities in 2006 were the result of increased borrowings, primarily to fund acquisitions.

In connection with our merger with KCS, on July 12, 2006, we consummated a private placement of 9 $^{1}/8$% senior notes. These notes were issued at 98.735% of the face amount of $650 million 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 to fund the $450 million that was paid to KCS stockholders in connection with the merger. We issued an additional $125 million of these notes 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 senior revolving credit facility.

In connection with the North Louisiana Acquisitions, on February 1, 2006, we issued and sold 13.0 million shares of our common stock for $14.50 per share, for gross proceeds of approximately $188.5 million. Contemporaneously with the offering, we repurchased approximately 3.3 million shares of our common stock for $46.2 million from EnCap Investments, L.P. and certain of its affiliates. We incurred a total of $10.7 million of offering costs during 2006.

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During the third quarter of 2005, we acquired Mission for consideration consisting of approximately $210 million of our common stock and $96.5 million in cash, net of cash acquired. We also assumed $184 million of Mission s long-term debt.

During the first quarter of 2005, we completed the acquisition of Proton for $52.6 million in cash, as well as the disposition of certain royalty interest properties previously acquired from Wynn-Crosby for approximately $80 million.

Net cash provided by financing activities in 2004 was primarily driven by the following long-term debt issuances:

- In connection with the acquisition of Wynn-Crosby, we entered into a new revolving credit facility with BNP Paribas as the lead bank that was due in November 2008. The revolving credit facility had an initial borrowing base of $200 million and a threshold amount of $180 million. Subsequent to the closing of the Wynn-Crosby acquisition, we have amended and restated our senior revolving credit facility. Refer to *Senior Revolving Credit Facility* under Item 7. *Management s Discussion and Analysis of Financial Condition and Results of Operations* for more details;

- A second lien facility in the amount of $50 million was also provided by BNP Paribas and a group of lenders that was due February 24, 2009. On July 12, 2006, in connection with our merger with KCS, we repaid all amounts outstanding under, and terminated, this facility; and

- In connection with the recapitalization of the Company by PHAWK, LLC, we issued a $35 million five-year unsecured subordinated convertible note payable to PHAWK, LLC. On June 30, 2005, we entered into an agreement with PHAWK, LLC to convert this note payable to common stock as stipulated in the original agreement.

We also received net proceeds of approximately $200 million for the issuance of 2,580,645 share of Series B 8% automatically convertible preferred stock in 2004. The proceeds from this offering and the related financing transactions discussed above were used to fund a portion of the purchase price of Wynn-Crosby.

These cash receipts were offset by the repayment of long-term debt of $69 million, including approximately $41 million for the repayment outstanding long-term debt of Wynn-Crosby assumed in the closing of the transaction as well as the repayment of approximately $13 million of long-term debt upon the closing of the recapitalization of the Company in 2004.

Financing activities in 2006 included $14.6 million of cash paid on settled derivative contracts that were acquired in conjunction with our acquisition activity in 2006 and $28.9 million in 2005.

During 2006, we paid dividends of $0.1 million on our 8% cumulative convertible preferred stock that were accrued during the fourth quarter of 2005, as well as first and second quarter 2006 dividends of $0.1 million each. In April 2006, we initiated a buyback of this preferred stock for $9.25 per share, resulting in a $4.4 million use of cash from financing activities. During 2005, we paid $0.3 million of the $0.4 million declared dividends on our 8% cumulative convertible preferred stock, with the remaining $0.1 million accrued in current liabilities and paid in January 2006. During 2004, we paid $0.6 million in dividends on our 8% cumulative convertible preferred stock.

We believe that we have the ability to finance through new debt or equity offerings, if necessary, our capital requirements, including acquisitions.

Contractual Obligations

We have no material long-term commitments associated with our capital expenditure plans or operating agreements. Consequently, we believe we have a significant degree of flexibility to adjust the level of such expenditures as circumstances warrant. Our level of capital expenditures will vary in future periods depending on

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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 (in thousands).

	Payments Due by Period				
Contractual Obligations	**Total**	**Less than one year**	**1-3 years**	**3-5 years**	**More than 5 years**
Revolving credit facility	$ 295,000	$	$	$ 295,000	$
9 7/8% senior notes due 2011	254			254	
7 1/8% senior notes due 2012 [(1)]	275,000				275,000
9 1/8% senior notes due 2013 [(2)]	775,000				775,000
Interest expense on long-term debt [(3)]	637,002	110,500	221,000	191,579	113,923
Deferred premiums on derivatives [(4)]	5,700	5,700			
Rig commitments	78,946	45,724	31,436	1,786	
Operating leases	19,907	3,324	6,004	5,607	4,972
Total contractual obligations	$ 2,086,809	$ 165,248	$ 258,440	$ 494,226	$ 1,168,895

(1) *Excludes $12.5 million of unamortized discount recorded in conjunction with our merger with KCS. See 7 1/8% Senior Notes below for more details.*

(2) *Excludes net $6.5 million discount recorded in conjunction with the issuance of the notes. See 9 1/8% Senior Notes below for more details.*

(3) *Future interest expense was calculated based on interest rates and amounts outstanding at December 31, 2006 less required annual repayments.*

(4) *This amount has been classified as current at December 31, 2006.*

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, 2006 is $45.3 million.

Senior Revolving Credit Facility

In connection with our merger with KCS, we amended and restated our senior revolving credit facility. The facility provides for a $1 billion commitment with a borrowing base that will be redetermined on a semi-annual basis. We and the lenders each have the right to one annual interim unscheduled redetermination to adjust the borrowing base based on our and gas properties, reserves, other indebtedness and other relevant factors. At December 31, 2006, the borrowing base was $710 million. Amounts outstanding bear interest at specified margins over LIBOR of 1.00% to 1.75% for Eurodollar loans or at specified margins over ABR of 0.00% to 0.50% for ABR loans. Such margins fluctuate based on the utilization of the facility. Borrowings are secured by first priority liens on substantially all of our assets and all of the assets of, and equity interest in, our subsidiaries. Amounts drawn down on the facility will mature on July 12, 2010.

The senior revolving credit facility contains customary financial and other covenants, including minimum working capital levels, minimum coverage of interest expense, and a maximum leverage ratio. 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, 2006, we were in compliance with all of our debt covenants under the senior revolving credit facility.

7 1/8% Senior Notes

Upon effectiveness of our merger with KCS, we assumed (pursuant to the Second Supplemental Indenture relating to the 7 1/8% Senior Notes, also referred to as the 2012 Notes), and our subsidiaries guaranteed (pursuant to the Third Supplemental Indenture relating to such notes), all the obligations (approximately $275 million) of

KCS under the 2012 Notes and the Indenture dated April 1, 2004 (the 2012 Indenture) among KCS, U.S. Bank National Association, as trustee, and the subsidiary guarantors named therein, which governs the terms of the 7 1/8% senior notes due 2012. The 2012 Notes are guaranteed on an unsubordinated, unsecured basis by all of our current subsidiaries, including the subsidiaries of KCS that we acquired in the merger. Interest on the 2012 Notes is payable semi-annually, on each April 1 and October 1. At any time prior to April 1, 2007, we may redeem up to 35% of the aggregate original principal amount of the 2012 Notes, using the net proceeds of equity offerings, at a redemption price equal to 107.125% of the principal amount of the 2012 Notes, plus accrued and unpaid interest. On or after April 1, 2008, we may redeem all or a portion of the 2012 Notes at a redemption price equal to 100% of the principal amount plus accrued and unpaid interest, if any, plus a specified premium which decreases annually from 3.568% in 2008 to 0% in 2010 and thereafter.

The 2012 Indenture contains a provision requiring us to offer to purchase the 2012 Notes at 101% of face value in the event of a change of control (as defined in the 2012 Indenture). Certain 2012 Note holders have alleged that the merger constituted a change of control as set forth in the 2012 Indenture. Based upon consultation with counsel, we do not believe that a change of control occurred. See Item 8. *Consolidated Financial Statements and Supplementary Data* Note *6, Commitments and Contingencies,* for more details. At December 31, 2006, we were in compliance with all of our debt covenants under the 7 1/8% Senior Notes.

In conjunction with the assumption of the 7 1/8% 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 is $12.5 million at December 31, 2006.

9 1/8% Senior Notes

On July 12, 2006, we consummated a private placement of 9 1/8% 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. The 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 7/8% notes due 2011 (2011 Notes) pursuant to a tender offer we concluded in July 2006.

The 2013 Notes bear interest at the rate of 9.125% per annum, payable semi-annually on January 15 and July 15 of each year, commencing January 15, 2007. The 2013 Notes mature on July 15, 2013. The 2013 Notes are senior unsecured obligations and rank equally with all of our current and future senior indebtedness, including the 2012 Notes. The 2013 Notes rank effectively subordinate to our secured debt to the extent of the collateral, including secured debt under the revolving credit facility, and senior to any future subordinated indebtedness. The 2013 Notes are jointly and severally guaranteed on a senior unsecured basis by our subsidiaries, including, pursuant to the 2013 First Supplemental Indenture, the KCS subsidiaries acquired in our merger with KCS.

On or before July 15, 2009, we may redeem up to 35% of the aggregate principal amount of the 2013 Notes with the net cash proceeds of certain equity offerings at a redemption price of 109.13% of the principal amount plus accrued interest and unpaid interest to the redemption date provided that: (i) at least 65% in aggregate principal amount of the 2013 Notes originally issued under the 2013 Indenture remain outstanding immediately after the redemption (excluding 2013 Notes held by us and our subsidiaries); and (ii) each redemption must occur within 90 days of the date of the closing of the related equity offering.

In addition, on or before July 15, 2010, we may redeem all or part of the 2013 Notes upon not less than 30 nor more than 60 days notice, at a redemption price equal to the sum of (i) the principal amount, plus (ii) accrued and unpaid interest, if any, to the redemption date, plus (iii) the make whole premium at the redemption date.

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On or after July 15, 2010, we may redeem some or all of the 2013 Notes at any time. If any of the 2013 Notes are redeemed during any 12-month period beginning on July 15 of the year indicated below, we must pay the following redemption prices (expressed as percentages of principal amount) plus accrued and unpaid interest thereon, if any, to the applicable redemption date:

Year	Percentage
2010	104.563
2011	102.281
2012	100.000

We may be required to offer to repurchase the 2013 Notes at a purchase price of 101% of the principal amount, plus accrued and unpaid interest, if any, to the redemption date, in the event of a change of control, as defined in the 2013 Indenture. Additionally, we may be required to offer to repurchase the 2013 Notes, and to the extent required by the terms thereof, all other indebtedness (as defined in the 2013 Indenture) that is *pari passu* with the 2013 Notes at a purchase price of 100% of the principal amount (or accreted value in the case of any such other *pari passu* indebtedness issued with a significant original issue discount) plus accrued and unpaid interest, if any, to the date of purchase, in the event net proceeds from assets sales are not applied as required by the 2013 Indenture.

The 2013 Indenture contains covenants that, among other things, restrict or limit our and our subsidiaries ability to: (i) borrow money; (ii) pay dividends on stock; (iii) purchase or redeem stock or subordinated indebtedness; (iv) make investments; (v) create liens; (vi) enter into transactions with affiliates; (vii) sell assets; and (viii) merge with or into other companies or transfer all or substantially all of our assets. Additionally, the Indenture covering the 2013 Notes contains a provision which provides for a rate increase of 1/8 of one percent if we refinance any part of its 2012 Notes on or before July 11, 2007.

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 of 2013 Notes were issued pursuant to the 2013 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 senior revolving credit facility. At December 31, 2006, we were in compliance with all of our debt covenants relating to the 2013 Notes.

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 $7.8 million at December 31, 2006. In conjunction with the issuance of the additional $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 $1.3 million at December 31, 2006.

9 ^{7}/8% Senior Notes

On April 8, 2004, Mission issued $130.0 million of its 9 ^{7}/8% 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 for a premium of $14.9 million plus accrued interest of $3.5 million.

Off-Balance Sheet Arrangements

At December 31, 2006 and 2005, we did not have any off-balance sheet arrangements.

Plan of Operation for 2007

On an annual basis, we expect to fund most of our capital and exploration activities, excluding major oil and natural gas property acquisitions, with cash generated from operations and, when necessary, with borrowings under our senior revolving credit facility. We budget these capital expenditures based on our projected cash flows for the year. We have budgeted $575 million in capital expenditures for 2007.

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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 of America. 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 of America. 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 special, 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 and natural gas properties included in a cost center against the net present value of future cash flows from the related proved reserves, using period-end prices and costs and 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 of America 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 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 period-end 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, 2006 and 2005 were prepared by Netherland, Sewell, an independent oil and natural gas reservoir engineering consulting firm. The December 31, 2004 proved reserve estimates were prepared by Netherland, Sewell with the exception of 26.2 Bcfe of proved reserves associated with royalty interest properties acquired from Wynn-Crosby and subsequently sold on February 25, 2005 which were not part of Netherland, Sewell s report. 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.*

Depreciation, Depletion and Amortization

Our rate of recording depreciation, depletion and amortization expense (DD&A) is 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 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 $0.15 to $0.17 per Mcfe, respectively.

Full Cost Ceiling 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 writedown 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 prices and costs in effect as of the last day of the quarter are held constant. However, we may not be subject to a writedown if prices increase subsequent to the end of a quarter in which a writedown might otherwise be required. If oil and natural gas prices decline, even if for only a short period of time, or if we have downward revisions to our estimated proved reserves, it is possible that writedowns of our oil and natural gas properties could occur in the future.

Future Development and Abandonment 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

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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 positive or negative change in future development and abandonment costs would decrease or increase the DD&A rate by approximately $0.05 per Mcfe.

Asset Retirement Obligations

We have significant obligations to remove tangible equipment and facilities and to restore land at the end of oil and gas production operations. Our removal and restoration obligations are associated with plugging and abandoning wells. 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.

Allocation of Purchase Price in Business Combinations

As part of our business strategy, we actively pursue the acquisition of oil and natural gas properties. The purchase price in an acquisition is allocated to the assets acquired and liabilities assumed based on their relative fair values as of the acquisition date, which may occur many months after the announcement date. Therefore, while the consideration to be paid may be fixed, the fair value of the assets acquired and liabilities assumed is subject to change during the period between the announcement date and the acquisition date. Our most significant estimates in our allocation typically relate to the value assigned to future recoverable oil and natural gas reserves and unproved properties. As the allocation of the purchase price is subject to significant estimates and subjective judgments, the accuracy of this assessment is inherently uncertain.

Effective January 1, 2002, we adopted SFAS No. 142, *Goodwill and Other Intangible Assets*, under which goodwill is no longer subject to amortization. Rather, goodwill of each reporting unit is tested for impairment on an annual basis, or more frequently if an event occurs or circumstances change that would reduce the fair value of the reporting unit below its carrying amount. The 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 writedown is charged against earnings.

We completed our annual impairment review during the third quarter of 2006. No impairment was deemed necessary. Downward revisions of estimated reserves or production, increases in estimated future costs or decreases in oil and natural gas prices could lead to an impairment of all or a portion of our goodwill in future periods.

Accounting for Derivative Instruments and Hedging Activities

We utilize derivative contracts to hedge against the variability in cash flows associated with the forecasted sale of our anticipated future oil and natural gas production. We generally hedge a substantial, but varying, portion of our anticipated oil and natural gas production for the next 12-36 months. We do not use derivative instruments for trading purposes. We have elected not to apply hedge accounting to our derivative contracts, which would potentially allow us to not record the change in fair value of our derivative contracts in the statement of operations. We carry our derivatives at fair value on our consolidated balance sheet, with the changes in the fair value included in our statement of operations in the period in which the change occurs. Our results of operations would potentially have been significantly different had we elected and qualified for hedge accounting on our derivative contracts.

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Comparison of Results of Operations

Year Ended December 31, 2006 Compared to Year Ended December 31, 2005

We had net income of $116.6 million for the year ended December 31, 2006 compared to a net loss of $16.6 million for 2005. The increase in net income is primarily due to our pre-tax gain on derivative contracts of $124.4 million in 2006 compared to a net loss on derivative contracts of $100.4 million in 2005.

The following table summarizes key items of comparison and their related increase (decrease) for the years ended December 31 for the periods indicated.

	Years Ended December 31,		Increase
In thousands (except per unit and per Mcfe amounts)	**2006**	**2005**	**(Decrease)**
Net income (loss)	$ 116,563	$ (16,634)	$ 133,197
Oil and gas sales	587,762	258,039	329,723
Expenses:			
Production:			
Lease operating	58,029	30,784	27,245
Workover and other	8,118	3,265	4,853
Taxes other than income	45,547	18,497	27,050
Gathering, transportation and other	16,187	2,030	14,157
General and administrative:			
General and administrative	35,827	21,214	14,613
Stock-based compensation	8,242	3,820	4,422
Depletion, depreciation and amortization:			
Depletion Full cost	257,593	72,716	184,877
Depreciation Other	2,135	666	1,469
Accretion expense	1,544	1,157	387
Net gain (loss) on derivative contracts:	124,442	(100,380)	224,822
Interest expense and other	(89,884)	(29,207)	(60,677)
Income tax (provision) benefit	(72,535)	9,063	(81,598)
Production:			
Natural Gas MMcf [(1)]	63,643	20,219	43,424
Crude Oil MBbl	2,703	1,555	1,148
Natural Gas Equivalent MMcfe	79,863	29,549	50,314
Average Daily Production MMcfe	219	81	138
Average price per unit [(2)]:			
Gas price per Mcf [(1)]	$ 6.57	$ 8.46	$ (1.89)
Oil price per Bbl	62.27	55.62	6.65
Equivalent per Mcfe	7.34	8.73	(1.39)
Average cost per Mcfe:			
Production:			
Lease operating	0.73	1.04	(0.31)
Workover and other	0.10	0.11	(0.01)
Taxes other than income	0.57	0.63	(0.06)
Gathering, transportation and other	0.20	0.07	0.13
General and administrative:			
General and administrative	0.45	0.72	(0.27)
Stock-based compensation	0.10	0.13	(0.03)
Depletion expense	3.23	2.46	0.77

(1)

Approximately 5% and 7% of natural gas production represents natural gas liquids (calculated with a 6:1 equivalent ratio) with an average price of $36.88 per Bbl and $40.50 per Bbl for the years ended December 31, 2006 and 2005, respectively.

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

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For the year ended December 31, 2006, oil and natural gas sales increased $329.7 million, from the same period in 2005, to $587.8 million. The increase for the year was primarily due to the increase in production of 50,314 MMcfe, of which 31,290 MMcfe related to our merger with KCS. The remaining increase in volumes was due to the inclusion of a full year of production for Mission as well as the closing of the North Louisiana Acquisitions in January 2006 as well as our increased drilling success. This increase in production led to an approximate $440.7 million increase in revenues from the prior year which was offset by a decrease in commodity prices that led to an approximate $111.0 million decrease in revenues from the prior year. Our realized average price per Mcfe decreased $1.39 in 2006 to $7.34 from $8.73 in 2005.

Lease operating expenses increased $27.2 million from the prior year. The increase was primarily due to the increase in production volumes as a result of our recent acquisition and divestiture activities, as well as a continued increase in overall activity in 2006. We drilled 330 gross wells in 2006 compared to 146 gross wells in 2005. On a per unit basis, lease operating expenses decreased 29.8% from $1.04 per Mcfe in 2005 to $0.73 per Mcfe in 2006. The decrease on a per unit basis is primarily due to our continued cost control efforts to lower our lease operating expenses. We continue to identify divestment prospects which tend to be outlying, higher operating cost properties as evident by the transactions that closed during the fourth quarter of 2006. Also contributing to decrease on a per unit basis was our acquisition of lower cost properties as a consequence of our merger with KCS and properties acquired in the North Louisiana Acquisitions.

Workover and other expense increased $4.9 million for the year ended December 31, 2006 as compared to 2005. The increase was primarily due to the increase in major maintenance activities in 2006. On a per unit basis, workover and other expense decreased $0.01 per Mcfe to $0.10 per Mcfe in 2006 as our increase in production volume has exceeded the increase in workover expense.

Taxes other than income increased $27.1 million for the year ended December 31, 2006 as compared to the same period in 2005. The largest components of taxes other than income are production and severance taxes which are generally assessed as a percentage of gross oil and natural gas sales. On a per unit basis, taxes other than income decreased $0.06 per Mcfe to $0.57 per Mcfe in 2006 as compared to $0.63 per Mcfe in 2005. As a percentage of oil and natural gas sales, taxes other than income remained substantially consistent at 7%.

Gathering, transportation and other expense increased $14.2 million for the year ended December 31, 2006 as compared to the same period in 2005. This increase is due to our recent acquisition activities including the completion of our merger with KCS as well as the North Louisiana Acquisitions.

General and administrative expense for the year ended December 31, 2006 increased $14.6 million to $35.8 million compared to $21.2 million in the same period in 2005. This increase was due to our continued growth over the past two years. In 2006, we completed the North Louisiana Acquisitions as well as our merger with KCS which increased compensation and other costs associated with increased staffing levels to meet the demands of our expanding operations. General and administrative expense has decreased significantly on a per Mcfe basis from $0.72 per Mcfe in 2005 to $0.45 per Mcfe in 2006 as production increases have exceeded our administrative expense increases. Operating in concentrated areas helps us to better control our overhead by enabling us to manage a greater amount of acreage with fewer employees and minimize incremental costs of increased drilling and production. Our strategy of targeting our operations in relatively focused areas permits us to more efficiently manage our general and administrative expenses.

Stock-based compensation increased $4.4 million for the year ended December 31, 2006 as compared to the same period in the prior year. This increase is primarily related to additional stock options and restricted stock grants assumed as part of our merger with KCS in July 2006, as well as the stock options and restricted stock grants given to employees and non-employee directors during 2006 and a full year of amortization for those grants that were issued during 2005.

Depletion expense increased $184.9 million from the same period in 2005 to $257.6 million for the year ended December 31, 2006. Depletion for oil and natural gas properties is calculated using the unit of production

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method, which essentially depletes the capitalized costs associated with the evaluated properties plus future development costs based on the ratio of production volume for the current period to total remaining reserve volume for the evaluated properties. On a per unit basis, depletion expense increased $0.77 per Mcfe to $3.23 from $2.46. This increase was due to our merger with KCS in July 2006, the North Louisiana Acquisitions in January 2006 and our merger with Mission in July 2005.

We enter into derivative commodity instruments to 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 valuation of these derivative contracts in the consolidated statement of operations. At December 31, 2006, we had a $75.2 million derivative asset, $68.2 million of which was classified as current, and a $19.8 million derivative liability, $8.0 million of which was classified as current. We recorded a net derivative gain of $124.4 million ($134.4 million unrealized gain and $10.0 million cash paid on settled contracts) for the year ended December 31, 2006 compared to a net derivative loss of $100.4 million in the prior year. The increase in our net derivative gain in the current year over the net derivative loss in the prior year is due to the decrease in commodity prices, primarily natural gas as the weighted average of the forward strip used to value our natural gas derivatives decreased from $10.41 per million British thermal unit (MMbtu) at December 31, 2005 to $7.29 per MMbtu at December 31, 2006.

Interest expense and other increased $60.7 million for the year ended December 31, 2006 compared to the same period in 2005. This increase was primarily due to additional debt we incurred in conjunction with our merger with KCS in July 2006, our merger with Mission in July 2005 and the closing of the North Louisiana Acquisitions in January 2006, as well as premiums paid to extinguish previously assumed Mission debt.

Income tax expense for the year ended December 31, 2006 increased $81.6 million from the prior year. The increase in income tax expense from prior year is primarily due to our pre-tax income of $189.1 million in 2006 compared to a pre-tax net loss of $25.7 million in 2005. The effective tax rates for the years ended December 31, 2006 and 2005 were 38.4% and 35.3%, respectively. The increase in our effective tax rate from the prior year is primarily due to changes in state apportionment percentages due to the merger of KCS properties with historical Petrohawk properties. Also adding to this increase was an increase in our effective tax rate for the recognition of a change in the Texas state franchise tax rate due to a change in the tax law. In May 2006, the State of Texas enacted substantial changes to its tax structure beginning in 2007 by imposing a new tax based upon modified gross revenue referred to as the Margin Tax. We determined the Margin Tax to be an income tax as defined under Statement of Financial Accounting Standards No. 109, *Accounting for Income Taxes.*

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Year Ended December 31, 2005 Compared to Year Ended December 31, 2004

We had a net loss of $16.6 million for the year ended December 31, 2005 compared to net income of $8.1 million for 2004. The net loss in 2005 resulted from a pre-tax loss on derivative contracts of $100.4 million.

The following table summarizes key items of comparison and their related increase (decrease) for the years ended December 31 for the periods indicated.

	Years Ended December 31,		Increase
In thousands (except per unit and per Mcfe amounts)	**2005**	**2004**	**(Decrease)**
Net (loss) income	$ (16,634)	$ 8,117	$ (24,751)
Oil and gas sales	258,039	33,577	224,462
Expenses:			
Production:			
Lease operating	30,784	5,540	25,244
Workover and other	3,265	294	2,971
Taxes other than income	18,497	2,319	16,178
Gathering, transportation and other	2,030	26	2,004
General and administrative:			
General and administrative	21,214	7,802	13,412
Stock-based compensation	3,820	3,529	291
Depletion, depreciation and amortization:			
Depletion Full cost	72,716	9,117	63,599
Depreciation Other	666	114	552
Accretion expense	1,157	137	1,020
Net (loss) gain on derivative contracts:	(100,380)	7,441	(107,821)
Interest expense and other	(29,207)	(2,894)	(26,313)
Income tax benefit (provision)	9,063	(1,129)	10,192
Production:			
Natural Gas MMcf (1)	20,219	3,569	16,650
Crude Oil MBbl	1,555	244	1,311
Natural Gas Equivalent MMcfe	29,549	5,030	24,519
Average Daily Production MMcfe	81	14	67
Average price per unit (2):			
Gas price per Mcf (1)	$ 8.46	$ 6.53	$ 1.93
Oil price per Bbl	55.62	40.71	14.91
Equivalent per Mcfe	8.73	6.61	2.12
Average cost per Mcfe:			
Production:			
Lease operating	1.04	1.10	(0.06)
Workover and other	0.11	0.06	0.05
Taxes other than income	0.63	0.46	0.17
Gathering, transportation and other	0.07	0.01	0.06
General and administrative:			
General and administrative	0.72	1.55	(0.83)
Stock-based compensation	0.13	0.70	(0.57)
Depletion expense	2.46	1.81	0.65

(1) *Approximately 7% of natural gas production represents natural gas liquids (calculated with a 6:1 equivalent ratio) with an average price of $40.50 per Bbl for the year ended December 31, 2005. Natural gas liquids represented less than 1% of natural gas production for the year ended December 31, 2004.*

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

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For the year ended December 31, 2005, oil and natural gas sales increased $224.5 million, from the same period in 2004, to $258.0 million. The increase for the year was primarily due to the increase in production of 24,519 MMcfe, of which 8,798 MMcfe related to our merger with Mission in July 2005 and 1,907 MMcfe related to the acquisition of Proton in 2005. The remaining increase in volumes was due to the inclusion of a full year of production for Wynn-Crosby as well as our increased drilling success. Higher commodity prices led to an approximate $62.6 million increase in revenues from the prior year as our realized average price per Mcfe increased $2.12 in 2005 to $8.73 from $6.61 in 2004. Prices continued to be strong in 2005 due to a number of factors including Hurricanes Rita and Katrina, inventory storage levels and continued supply concerns due to both domestic and global events.

Lease operating expenses increased $25.2 million for the year ended December 31, 2005 as compared to the same period in 2004. The increase was primarily due to the acquisition of Wynn-Crosby in November 2004, Mission in July 2005 and Proton in February 2005, as well as an increase in overall activity in 2005. We drilled 146 gross wells in 2005 compared to only 71 gross wells in 2004. On a per unit basis, lease operating expenses decreased 5% from $1.10 per Mcfe in 2004 to $1.04 per Mcfe in 2005 primarily as our increase in production of 24,519 Mcfe offset the increase in overall costs.

Workover and other expense increased $3.0 million for the year ended December 31, 2005 as compared to the same period in 2004. The increase was primarily due to the increase in major maintenance activities as commodity prices have remained high as well as the acquisitions of Wynn-Crosby in 2004 and Proton and Mission in 2005. On a per unit basis, workover and other expense increased $0.05 per Mcfe to $0.11 per Mcfe in 2005 due to a number of higher cost activities that were undertaken by us based on the current period price environment.

Taxes other than income increased $16.2 million for the year ended December 31, 2005 as compared to the same period in 2004. A significant component of such increase related to production taxes which are generally assessed as a percentage of gross oil and/or natural gas sales. In general, production taxes increase as revenue and production increase.

Gathering, transportation and other expense increased $2.0 million for the year ended December 31, 2005 as compared to the same prior in 2004, due to the acquisition of Wynn-Crosby in November 2004 and Mission in July 2005.

General and administrative expense for the twelve months ended December 31, 2005 increased $13.4 million to $21.2 million compared to $7.8 million in the same period in 2004. This increase was directly related to our continued growth over the past two years. Office expenses increased with our relocation of the corporate office to Houston, Texas and the subsequent expansion of the office following the July 2005 acquisition of Mission. Salaries and benefits increased with the addition of new staff and annual salary increases for existing employees. Overall headcount increased to 154 full time employees in 2005 as compared to 43 in 2004, driven by the decision to bring the previously outsourced accounting function back in house as well as the recent acquisition activity. On an Mcfe basis, general and administrative costs decreased $0.83 per Mcfe in 2005 to $0.72 per Mcfe as compared to $1.55 per Mcfe in 2004 due to the synergies achieved from the Wynn-Crosby, Proton and Mission acquisitions. For the year ended December 31, 2005, stock-based compensation was $3.8 million, an increase of $0.3 million over prior year.

Accretion expense increased $1.0 million from the same period in 2004 to $1.2 million for the year ended December 31, 2005. The increase was due to the inclusion of a full year of accretion expense for Wynn-Crosby which increased the overall liability $10.8 million in 2004 and the acquisitions of Proton and Mission in 2005 which increased the liability $38.5 million in 2005.

Depletion expense increased $63.6 million from the same period in 2004 to $72.7 million for the year ended December 31, 2005. Depletion for oil and natural gas properties is calculated using the unit of production

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method, which essentially depletes the capitalized costs associated with the evaluated properties based on the ratio of production volume for the current period to total remaining reserve volume for the evaluated properties. On a per unit basis, depletion expense increased 36% from $1.81 to $2.46. This increase was due to our acquisition and divestiture activities in 2005.

Periodically, we enter into derivative commodity instruments to hedge our exposure to price fluctuations on oil and natural gas production. At December 31, 2005, we had a $3.5 million derivative asset, $1.3 million of which was classified as current, and an $86.8 million derivative liability, $51.1 million of which was classified as current. The change in the unrealized fair value of these derivative positions was included in earnings along with the realized losses incurred. We recorded a net derivative loss of $100.4 million for the year ended December 31, 2005 compared to a net gain of $7.4 million at December 31, 2004.

Interest expense and other increased $26.3 million for the year ended December 31, 2005 compared to the same period in 2004. This increase was primarily due to the assumption of $130 million of Mission s 9 7/8% notes due 2011, the expensing of debt issue costs, a one-time payment made upon conversion of the $35 million PHAWK Note during the second quarter of 2005 and to the $55 million increase in our senior revolving credit facility and the $100 million increase in our second lien term loan facility, most of which were used to fund the Mission acquisition.

Income tax benefit increased $10.2 million. This increase was primarily due to the increase in our pre-tax loss from prior year. Our 2005 effective tax rate was 35.3% compared to 12.2% in 2004. The difference in the rate is the result of a valuation allowance reversal of $2.4 million in 2004.

Related Party Transactions

A description of our related party transactions is included in Item 8. *Consolidated Financial Statements and Supplementary Data* Note *10, Related Party Transactions,* and is incorporated herein by reference.

Recently Issued Accounting Standards

We discuss recently adopted and issued accounting standards in Item 8. *Consolidated Financial Statements and Supplementary Data* Note 1, *Financial Statement Presentation.*

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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. We expect energy prices to remain volatile and unpredictable. If energy prices were to decline significantly, revenues and cash flow would significantly decline, and our ability to borrow to finance our operations could be adversely impacted. We have designed our hedging policy to reduce the risk of price volatility for our production in the natural gas and crude oil markets. Our risk management policy provides for the use of derivative instruments to manage these risks. The types of derivative instruments that we utilize include futures, swaps and options. The volume of derivative instruments that we may utilize is governed by the risk management policy and can vary from year to year, but under most circumstances will apply to only a portion of our current and anticipated production and provide only partial price protection against declines in oil and natural gas prices. We are exposed to market risk on our open contracts, to the extent of changes in market prices of oil and natural gas. However, the market risk exposure on these hedged contracts is generally offset by the gain or loss recognized upon the ultimate sale of the commodity that is hedged. Further, if our counterparties defaulted, this protection might be limited as we might not receive the benefits of the hedges. Please refer to Item 8. *Consolidated Financial Statements and Supplementary Data* Note 7, *Derivative Activities* for additional information.

Fair Market Value of Financial Instruments

The estimated fair values for financial instruments under Financial Accounting Standards Board Statement No. 107, *Disclosures about Fair Value of Financial Instruments*, 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. Please refer to Fair Value of Financial Instruments in Item 8. *Consolidated Financial Statements and Supplementary Data* Note 1, *Summary of Significant Events and Accounting Policies* 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, 2006, total debt was $1.3 billion, of which approximately 78.1%, or $1.0 billion, bears interest at a weighted average fixed interest rate of 8.6% per year. The remaining 21.9% of our total debt balance at December 31, 2006, or $295.0 million, 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, 2006, the interest rate on our variable rate debt was 6.4% per year. If the balance of our bank debt at December 31, 2006 were to remain constant, a 10% change in market interest rates would impact our cash flow by approximately $0.5 million per quarter.

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ITEM 8. CONSOLIDATED FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

INDEX TO CONSOLIDATED FINANCIAL STATEMENTS

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MANAGEMENT S REPORT ON INTERNAL CONTROL OVER FINANCIAL REPORTING

Management, 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. 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, 2006. Management excluded the acquisition of KCS Energy, Inc. (KCS) from its assessment of internal control over financial reporting as of December 31, 2006 because KCS was acquired in a business combination on July 12, 2006. KCS total assets, revenues and operating expenses constitute 55, 37 and 10 percent, respectively, of the related consolidated financial statements of the Company as of and for the year ended December 31, 2006.

Management s assessment of the effectiveness of internal control over financial reporting as of December 31, 2006, was audited by Deloitte & Touche LLP, an independent registered public accounting firm, as stated in their report which is included herein.

/s/ Floyd C. Wilson	/s/ Shane M. Bayless
Floyd C. Wilson	**Shane M. Bayless**
Chairman of the Board, President	**Executive Vice President,**
and Chief Executive Officer	**Chief Financial Officer and Treasurer**

Houston, Texas

February 27, 2007

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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 (formerly Beta Oil and Gas, Inc.) (the Company) as of December 31, 2006 and 2005, and the related consolidated statements of operations, stockholders equity, cash flows, and comprehensive income (loss) for each of the three years in the period ended December 31, 2006. We also have audited management s assessment, included in the accompanying Management s Report on Internal Control over Financial Reporting (Report of Management), that the Company maintained effective internal control over financial reporting as of December 31, 2006, based on criteria established in *Internal Control Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission. As described in Report of Management, management excluded from their assessment the internal control over financial reporting at KCS Energy, Inc. (KCS), which was acquired on July 12, 2006 and whose consolidated financial statements reflect total assets, revenues and operating expenses constituting 55, 37 and 10 percent, respectively, of the related consolidated financial statements of the Company as of and for the year ended December 31, 2006. Accordingly, our audit did not include the internal control over financial reporting at KCS. 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. Our responsibility is to express an opinion on these financial statements, an opinion on management s assessment and an opinion on the effectiveness of the Company s internal control over financial reporting based on our audits.

We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement and whether effective internal control over financial reporting was maintained in all material respects. Our audit of financial statements included examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, and evaluating the overall financial statement presentation. Our audit of internal control over financial reporting included obtaining an understanding of internal control over financial reporting, evaluating management s assessment, testing and evaluating the design and operating effectiveness of internal control, and performing such other procedures as we considered necessary in the circumstances. We believe that our audits provide a reasonable basis for our opinions.

A company s internal control over financial reporting is a process designed by, or under the supervision of, the company s principal executive and principal financial officers, or persons performing similar functions, and effected by the company s board of directors, management, and other personnel to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company s internal control over financial reporting includes those policies and procedures that (1) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (2) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (3) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company s assets that could have a material effect on the financial statements.

Because of the inherent limitations of internal control over financial reporting, including the possibility of collusion or improper management override of controls, material misstatements due to error or fraud may not be prevented or detected on a timely basis. Also, projections of any evaluation of the effectiveness of the internal control over financial reporting to future periods are subject to the risk that the controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

In our opinion, the consolidated financial statements referred to above present fairly, in all material respects, the financial position of Petrohawk Energy Corporation and subsidiaries as of December 31, 2006 and 2005, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2006, in conformity with accounting principles generally accepted in the United States of America. Also in our opinion, management s assessment that the Company maintained effective internal control over financial reporting as of December 31, 2006, is fairly stated, in all material respects, based on the criteria established in *Internal Control Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission. Furthermore, in our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2006, based on the criteria established in *Internal Control Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission.

/s/ DELOITTE & TOUCHE LLP

Houston, Texas

February 27, 2007

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PETROHAWK ENERGY CORPORATION

CONSOLIDATED STATEMENTS OF OPERATIONS

(In thousands, except per share amounts)

	Years Ended December 31,		
	2006	**2005**	**2004**
Operating revenues:			
Oil and gas	$ 587,762	$ 258,039	$ 33,577
Operating expenses:			
Production:			
Lease operating	58,029	30,784	5,540
Workover and other	8,118	3,265	294
Taxes other than income	45,547	18,497	2,319
Gathering, transportation and other	16,187	2,030	26
General and administrative:			
General and administrative	35,827	21,214	7,802
Stock-based compensation	8,242	3,820	3,529
Depletion, depreciation and amortization	261,272	74,539	9,368
Total operating expenses	433,222	154,149	28,878
Income from operations	154,540	103,890	4,699
Other income (expenses):			
Net gain (loss) on derivative contracts	124,442	(100,380)	7,441
Interest expense and other	(89,884)	(29,207)	(2,894)
Total other income (expenses)	34,558	(129,587)	4,547
Income (loss) before income taxes	189,098	(25,697)	9,246
Income tax (provision) benefit	(72,535)	9,063	(1,129)
Net income (loss)	116,563	(16,634)	8,117
Preferred dividends	(217)	(440)	(445)
Net income (loss) available to common stockholders	$ 116,346	$ (17,074)	$ 7,672
Earnings (loss) per share of common stock:			
Basic	$ 0.95	$ (0.31)	$ 0.71
Diluted	$ 0.92	$ (0.31)	$ 0.36
Weighted average shares outstanding:			
Basic	122,452	54,752	10,808
Diluted	126,135	54,752	25,690

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

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PETROHAWK ENERGY CORPORATION

CONSOLIDATED BALANCE SHEETS

(In thousands)

	December 31, 2006	December 31, 2005
Current assets:		
Cash	$ 5,593	$ 12,911
Accounts receivable	155,582	68,087
Current portion of deferred income taxes		18,304
Receivables from derivative contracts	68,234	1,286
Prepaid expenses and other	17,303	5,393
Total current assets	246,712	105,981
Oil and gas properties (full cost method):		
Evaluated	2,901,649	1,096,810
Unevaluated	537,611	162,133
Gross oil and gas properties	3,439,260	1,258,943
Less accumulated depletion	(379,017)	(121,456)
Net oil and gas properties	3,060,243	1,137,487
Other operating property and equipment:		
Gas gathering system and equipment	1,512	1,508
Other	8,030	3,555
Gross other operating property and equipment	9,542	5,063
Less accumulated depreciation	(3,742)	(1,600)
Net other operating property and equipment	5,800	3,463
Other noncurrent assets:		
Goodwill	938,584	132,029
Debt issuance costs, net of amortization	14,987	1,969
Receivables from derivative contracts	6,995	2,252
Other	6,335	26,993
Total assets	$ 4,279,656	$ 1,410,174
Current liabilities:		
Accounts payable and accrued liabilities	$ 295,951	$ 90,017
Current portion of deferred income taxes	22,382	
Liabilities from derivative contracts	7,986	51,081
Current portion of long-term debt	5,700	2,788
Total current liabilities	332,019	143,886
Long-term debt	1,326,239	495,801
Liabilities from derivative contracts	11,803	35,695

Asset retirement obligations	45,326	50,133
Deferred income taxes	633,883	153,155
Other noncurrent liabilities	2,042	5,046
Commitments and contingencies (Note 6)		
Stockholders equity:		
Convertible preferred stock: 5,000,000 shares of $.001 par value authorized; no shares issued or outstanding at December 31, 2006 and 593,271 at December 31, 2005;		1
Common stock: 300,000,000 and 125,000,000 shares of $.001 par value authorized at December 31, 2006 and 2005, respectively; 168,486,732 and 73,566,117 shares issued and outstanding at December 31, 2006 and 2005, respectively	169	74
Additional paid-in capital	1,843,862	558,452
Treasury stock, at cost, 8,382 shares at December 31, 2005, retired at December 31, 2006		(36)
Retained earnings (accumulated deficit)	84,313	(32,033)
Total stockholders equity	1,928,344	526,458
Total liabilities and stockholders equity	$ 4,279,656	$ 1,410,174

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

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PETROHAWK ENERGY CORPORATION

CONSOLIDATED STATEMENTS OF STOCKHOLDERS EQUITY

(In thousands)

	Preferred Shares	Preferred Amount	Common Shares	Common Amount	Additional Paid in Capital	Treasury Stock	Accumulated Deficit	Total Stockholders Equity
Balances at December 31, 2004	604	$ 1	6,223	$ 6	$ 51,930	$ (36)	$ (22,631)	$ 29,270
Equity compensation vesting			179		2,131			2,131
Warrants					2,027			2,027
Preferred stock acquired	(6)				(55)			(55)
Preferred stock private placement	2,581	3			199,997			200,000
Preferred stock private placement conversion to common stock	(2,581)	(3)	25,806	26	(23)			
Return of Capital to PHAWK, LLC					(3,550)			(3,550)
Offering costs					(15,466)			(15,466)
Preferred stock dividends							(445)	(445)
Common stock issuances			7,580	8	25,054			25,062
Net income							8,117	8,117
Balances at December 31, 2004	598	$ 1	39,788	$ 40	$ 262,045	$ (36)	$ (14,959)	$ 247,091
Equity compensation vesting					3,449			3,449
Common stock issued for purchase of Mission Resources			19,565	19	209,909			209,928
Conversion of PHAWK LLC Note			8,750	9	34,991			35,000
Warrants exercised			1,645	2	(2)			
Equity related to Mission s vested options					27,302			27,302
Preferred stock dividends							(440)	(440)
Repurchase of preferred stock	(5)				(46)			(46)
Common stock issuances			3,818	4	12,517			12,521
Tax benefit from exercise of stock options					8,287			8,287
Net loss							(16,634)	(16,634)
Balances at December 31, 2005	593	$ 1	73,566	$ 74	$ 558,452	$ (36)	$ (32,033)	$ 526,458
Equity compensation vesting					10,618			10,618
Common stock issued for purchase of KCS Energy, Inc.			83,862	84	1,146,518			1,146,602
Issuance of common stock			13,000	13	188,487			188,500
Encap shares retired			(3,322)	(3)	(46,197)			(46,200)
Preferred stock dividends							(217)	(217)
Repurchase of preferred stock	(593)	(1)			(5,487)			(5,488)
Retirement of Treasury shares			(8)		(36)	36		
Common stock issuances			1,389	1	2,449			2,450
Offering costs					(10,942)			(10,942)
Net income							116,563	116,563
Balances at December 31, 2006			168,487	$ 169	$ 1,843,862	$	$ 84,313	$ 1,928,344

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

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PETROHAWK ENERGY CORPORATION

CONSOLIDATED STATEMENTS OF CASH FLOWS

(In thousands)

	Years Ended December 31, 2006	2005	2004
Cash flows from operating activities:			
Net income (loss)	$ 116,563	$ (16,634)	$ 8,117
Adjustments to reconcile net income (loss) to net cash provided by operating activities:			
Depletion, depreciation and amortization	261,272	74,539	9,368
Income tax provision (benefit)	72,535	(9,063)	1,129
Stock-based compensation	8,242	3,820	3,529
Net unrealized (gain) loss on derivative contracts	(134,428)	64,180	(8,603)
Net realized loss on derivative contracts acquired	14,646	28,931	
Other	1,469	(64)	273
Change in assets and liabilities, net of acquisitions:			
Accounts receivable	(16,664)	(17,472)	3,266
Prepaid expenses and other	(6,373)	114	(815)
Accounts payable and accrued liabilities	(19,231)	7,828	1,679
Other	(1,138)	(733)	
Net cash provided by operating activities	296,893	135,446	17,943
Cash flows from investing activities:			
Oil and gas capital expenditures	(395,479)	(121,041)	(12,842)
Acquisition of KCS, net of cash acquired of $8,260	(512,344)		
Acquisition of Winwell Resources, Inc., net of cash acquired of $14,965	(177,264)		
Acquisition of Mission Resources, net of cash acquired of $48,359		(96,545)	
Acquisition of Proton Oil & Gas Corp., net of cash acquired of $870		(52,625)	
Acquisition of Wynn-Crosby, net of cash acquired of $2,584			(384,521)
Acquisition of oil and gas properties	(87,893)		(2,636)
Proceeds reveived from sale of oil and gas properties	192,424	88,900	839
Other	7,990	(24,798)	(1,321)
Net cash used in investing activities	(972,566)	(206,109)	(400,481)
Cash flows from financing activities:			
Proceeds from exercise of options	2,850	12,055	
Proceeds from issuance of common stock and warrants	188,500		25,629
Proceeds from issuance of subordinated convertible note payable			35,000
Acquisition of common stock	(46,200)		
Proceeds from borrowings	1,681,183	375,000	220,000
Repayment of borrowings	(1,111,644)	(279,510)	(68,689)
Proceeds from Series B preferred stock private placement			200,000
Debt issue costs	(14,438)		(4,089)
Return of capital to PHAWK, LLC			(5,684)
Net realized loss on derivative contracts acquired	(14,646)	(28,931)	
Offering costs	(10,942)		(15,466)
Buyback of 8% cumulative preferred stock	(5,340)		
Dividends paid on 8% cumulative preferred stock	(328)	(331)	(558)
Other	(640)	(369)	(55)

Net cash provided by financing activities	668,355	77,914	386,088
Net (decrease) increase in cash	(7,318)	7,251	3,550
Cash at beginning of period	12,911	5,660	2,110
Cash at end of period	$ 5,593	$ 12,911	$ 5,660

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

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PETROHAWK ENERGY CORPORATION

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS

1. SUMMARY OF SIGNIFICANT EVENTS AND ACCOUNTING POLICIES

Basis of Presentation and Principles of Consolidation

Petrohawk Energy Corporation (Petrohawk or the Company) is an independent oil and natural gas company engaged in the acquisition, development, production and exploration of oil and natural gas properties located in onshore North America. The Company operates in one segment, oil and natural gas exploration and exploitation. The consolidated financial statements include the accounts of all majority-owned, controlled subsidiaries. All significant intercompany accounts and transactions have been eliminated. Certain prior year amounts have been reclassified to conform to the current year presentation.

On July 12, 2006, the Company completed its merger with KCS Energy, Inc. (KCS). Refer to Note 2, *Acquisitions and Divestitures* , for more details on the Company s merger with KCS and various related transactions.

On May 18, 2004, the Company s Board of Directors approved a one-for-two reverse stock split that was effective May 26, 2004. The reverse stock split was implemented to effect the conditional approval by the NASDAQ National Market of the Company s listing application, which was later formally approved.

Use of Estimates

The preparation of the Company s consolidated financial statements in conformity with accounting principles generally accepted in the United States of America requires the Company s management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities, if any, at the date of the consolidated financial statements and the reported amounts of revenues and expenses during the respective reporting periods. These estimates include oil and natural gas reserve quantities which form the basis for the calculation of amortization of oil and natural gas properties. Management emphasizes that reserve estimates are inherently imprecise and that estimates of more recent reserve discoveries are more imprecise than those for properties with long production histories. Actual results may differ from the estimates and assumptions used in the preparation of our consolidated financial statements.

Allowance for Doubtful Accounts

The Company establishes provisions for losses on accounts receivable if it determines that it will not collect all or part of the outstanding balance. The Company regularly reviews collectibility and establishes or adjusts the allowance as necessary using the specific identification method. There is no significant allowance for doubtful accounts at December 31, 2006 and 2005.

Oil and Natural Gas Properties

The Company accounts for its oil and natural gas producing activities using the full cost method of accounting as prescribed by the United States Securities and Exchange Commission (SEC). Accordingly, all costs incurred in the acquisition, exploration, and development of proved oil and natural gas properties, including the costs of abandoned properties, dry holes, geophysical costs, and annual lease rentals are capitalized. All general and administrative corporate costs unrelated to drilling activities are expensed as incurred. Sales or other dispositions of oil and natural gas properties are accounted for as adjustments to capitalized costs, with no gain or loss recorded unless the ratio of cost to proved reserves would significantly change. Depletion of evaluated oil and natural gas properties is computed on the units of production method based on proved reserves. The net capitalized costs of proved oil and natural gas properties are subject to a full cost ceiling limitation in which the

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costs are not allowed to exceed their related estimated future net revenues discounted at 10%, net of tax considerations. Refer to Note 3 *Oil and Natural Gas Properties* for more details on the Company s December 31, 2006 ceiling test calculation.

Costs associated with unevaluated properties are excluded from the full cost pool until we have made a determination as to the existence of proved reserves. We review our unevaluated properties at the end of each quarter to determine whether the costs incurred should be transferred to the full cost pool and thereby subject to amortization.

Property, Plant and Equipment Other than Oil and Natural Gas Properties

Other operating property and equipment are stated at the lower of cost or fair market value. Provision for depreciation and amortization on property and equipment is calculated using the straight-line method over the estimated useful lives of the respective assets. The cost of normal maintenance and repairs is charged to operating expense as incurred. Material expenditures, which increase the life of an asset, are capitalized and depreciated over the estimated remaining useful life of the asset. The cost of properties sold, or otherwise disposed of, and the related accumulated depreciation or amortization are removed from the accounts and any gains or losses are reflected in current operations.

Impairment of Long-Lived Assets

In the event that facts and circumstances indicate that the costs of long-lived assets, other than oil and natural gas properties, may be impaired, an evaluation of recoverability would be performed. If an evaluation is required, the estimated future undiscounted cash flows associated with the asset would be compared to the asset s carrying amount to determine if a writedown to market value or discounted cash flow value is required. Impairment of oil and natural gas properties is evaluated subject to the full cost ceiling as described under the Oil and Natural Gas Properties section above.

Revenue Recognition

The Company recognizes oil and natural gas sales upon delivery to the purchaser. Under the sales method, the Company and other joint owners may sell more or less than their entitled share of the natural gas volume produced. Should the Company s excess sales of natural gas exceed its share of estimated remaining recoverable reserves, a liability is recorded by the Company and revenue is deferred.

Concentrations of Credit Risk

The Company operates a substantial portion of its oil and natural gas properties. As the operator of a property, the Company makes full payments for costs associated with the property and seeks reimbursement from the other working interest owners in the property for their share of those costs. The Company s joint interest partners consist primarily of independent oil and natural gas producers. If the oil and natural gas exploration and production industry in general were adversely affected, the ability of the Company s joint interest partners to reimburse the Company could be adversely affected.

The purchasers of the Company s oil and natural gas production consist primarily of independent marketers, major oil and natural gas companies and gas pipeline companies. The Company has not experienced any significant losses from uncollectible accounts. In 2006 and 2004, the Company had no individual purchasers accounting for more than 10% of total sales. In 2005, the Company had one individual purchaser that accounted for approximately 12% of total sales. The Company does not believe the loss of any one of its purchasers would materially affect the Company s ability to sell the oil and natural gas it produces. The Company believes other purchasers are available in the Company s areas of operations.

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Price Risk Management Activities

The Company follows Financial Accounting Standards Board (FASB) Statement of Financial Accounting Standards (SFAS) No. 133, *Accounting for Derivative Instruments and Hedging* Activities, as amended by SFAS No. 138, *Accounting for Certain Derivative Instruments and Certain Hedging Activities, an amendment of FASB Statement No. 133* and as amended by SFAS No. 149, *Amendment of Statement No. 133 on Derivative Instruments and Hedging Activities*. From time to time, the Company may hedge a portion of its forecasted oil and natural gas production. Derivative contracts entered into by the Company have consisted of transactions in which the Company hedges the variability of cash flow related to a forecasted transaction. The Company has elected to not designate any of its positions for hedge accounting for the years ended December 31, 2006, 2005 and 2004. Accordingly, the Company records the net change in the mark-to-market valuation on its derivative contracts in current earnings as a component of other income and expenses on the consolidated statements of operations.

Income Taxes

The Company accounts 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.

Asset Retirement Obligation

In August 2001, the FASB issued SFAS No. 143, *Accounting for Asset Retirement Obligations* (SFAS 143). The Company was required to adopt this new standard beginning January 1, 2003. SFAS 143 requires that the fair value of an asset retirement cost, and corresponding liability, should be recorded as part of the cost of the related long-lived asset and subsequently allocated to expense using a systematic and rational method. Upon adoption, the Company recorded an asset retirement obligation to reflect the Company s legal obligations related to future plugging and abandonment of its oil and natural gas wells. The Company estimated the expected cash flow associated with the obligation and discounted the amount using a credit-adjusted, risk-free interest rate. The transition adjustment resulting from the adoption of SFAS 143 was reported as a cumulative effect of a change in accounting principle. At least annually, the Company reassesses the obligation to determine whether a change in the estimated obligation is necessary. The Company evaluates whether there are indicators that suggest the estimated cash flows underlying the obligation have materially changed. Should those indicators suggest the estimated obligation may have materially changed on an interim basis (quarterly), the Company will accordingly update its assessment. Additional retirement obligations increase the liability associated with new oil and natural gas wells as these obligations are incurred.

Goodwill

Goodwill represents the excess of the purchase price over the estimated fair value of the assets acquired net of the fair value of liabilities assumed in the acquisition. SFAS No. 142, *Goodwill and Other Intangible Assets* (SFAS 142) 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 could potentially result in an impairment.

The 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 writedown is charged against earnings.

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The Company completed its annual impairment review during the third quarter of 2006. No impairment was deemed necessary. Downward revisions of estimated reserves or production, increases in estimated future costs or decreases in oil and natural gas prices could lead to an impairment of all or a portion of the Company s goodwill in future periods.

Fair Value of Financial Instruments

The estimated fair values for financial instruments under FASB Statement No. 107, *Disclosures about Fair Value of Financial Instruments*, 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. The estimated fair value of the Company s senior revolving credit facility and the Company s second lien term loan facility approximate carrying value because the facilities carry interest rates that approximate current market rates. The following table presents the estimated fair values of the Company s fixed interest rate debt instruments as of December 31, 2006:

	December 31, 2006	
Debt *(In thousands)*	**Carrying Amount**	**Estimated Fair Value**
9 $^{7}/8$% senior notes	$ 254	$ 254
9 $^{1}/8$% $775 mm senior notes	775,000	807,938
7 $^{1}/8$% $275 mm senior notes	275,000	266,750
	$ 1,050,254	$ 1,074,942

We account for our derivative activities under the provisions of SFAS 133, *Accounting for Derivative Instruments and Hedging Activities*, as amended. This statement, as amended, establishes accounting and reporting that every derivative instrument be recorded on the balance sheet as either an asset or liability measured at fair value. See Note 7, *Derivative and Hedging Activities* for more details.

Stock-Based Compensation

In January 2006, the Company adopted SFAS No. 123(R), *Share-Based Payment* (SFAS 123(R)). SFAS 123(R) revises SFAS No. 123, *Accounting for Stock-Based Compensation* (SFAS 123), and focuses on accounting for share-based payments for services provided by employee to employer. The statement requires companies to expense the fair value of employee stock options and other equity-based compensation at the grant date. The statement does not require a certain type of valuation model, and either a binomial or Black-Scholes model may be used. The Company used the modified prospective application method as detailed in SFAS No. 123(R).

Prior to adopting SFAS 123(R), the Company adopted SFAS No. 123, *Accounting for Stock-Based Compensation* (SFAS 123) prospectively, using the fair value recognition method to all employee and director awards granted, modified or settled after January 1, 2003. Prior to the adoption, the Company elected to follow Accounting Principles Board (APB) Opinion No. 25, *Accounting for Stock Issued to Employees* (APB 25) and related interpretations in accounting for its employee stock options. However, as required by SFAS 123, the Company disclosed on a pro forma basis the impact of the fair value accounting for employee stock options. Transactions in equity instruments with non-employees for goods or services have been accounted for using the fair value method as prescribed by SFAS 123.

Since the Company adopted the fair value recognition provisions of SFAS 123 prospectively for all employee awards granted, modified or settled after January 1, 2003, the cost related to stock-based compensation included in the determination of income for the year ended December 31, 2004, is less than that which would

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have been recognized if the fair value method had been applied to all awards since the original effective date of SFAS 123. Awards granted vest over a period ranging from one to three years; therefore, some grants made before January 1, 2003 vested in later periods and would represent costs in those periods.

The fair value of each option grant is calculated on the date of grant using the Black-Scholes option pricing model. The following table illustrates the approximated pro forma effect on net income and earnings per share as if the fair value based method had been applied to all outstanding and unvested awards in each period (in thousands).

	Year Ended December 31, 2004
Net income available to common stockholders as reported	$ 7,672
Add: Stock-based compensation expense included in reported net income, net of tax	2,201
Deduct: Total stock-based compensation expense determined under fair value method for all awards, net of tax	(2,330)
Pro forma net income available to common stockholders	$ 7,543
Earnings per share of common stock:	
Basic as reported	$ 0.71
Basic pro forma	$ 0.70
Diluted as reported	$ 0.36
Diluted pro forma	$ 0.35

There were no costs accounted for under APB 25 during the years ended December 31, 2006 and 2005.

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

	Years Ended December 31,		
	2006 (1)(2)	2005	2004
Weighted average value per option granted during the period (3)	$ 6.95	$ 2.31	$ 3.77
Assumptions (4):			
Stock price volatility	39.0%	29.3%	73.9%
Risk free rate of return	4.9%	3.6%	3.0%
Expected term	2.9 years	3.0 years	3.0 years

(1) *Includes assumptions from valuation related to the Company s merger with KCS. Refer to Note 8, Stockholders Equity for further details on these assumptions.*

(2) *The Company s estimated future forfeiture is 5% based on the Company s historical forfeiture rate.*

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

(4) *The Company does not pay dividends on its common stock.*

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The following table sets forth the option transactions for the years ended December 31, 2006, 2005 and 2004 (in thousands, except share and per share amounts).

	Number of Options	Weighted Average Exercise Price Per Share	Aggregate Intrinsic Value [1]	Weighted Average Remaining Contractual Life (Years)
Outstanding at December 31, 2003	1,716,542	$ 10.11		
Granted	5,717,500	3.83		
Exercised	(178,292)	3.51		
Forfeited	(254,867)	11.90		
Outstanding at December 31, 2004	7,000,883	$ 5.08	$ 24,363	5.4
Assumed in Merger with Mission	3,852,433	3.76		
Granted	1,404,300	9.37		
Exercised	(5,986,635)	3.26		
Forfeited	(572,434)	15.01		
Outstanding at December 31, 2005	5,698,547	$ 6.16	$ 40,232	5.6
KCS options assumed in merger	2,585,950	3.96		
Granted	1,877,270	11.97		
Exercised	(507,342)	6.08		
Forfeited	(428,212)	14.83		
Outstanding at December 31, 2006	9,226,213	$ 6.34	$ 47,607	6.0
Exercisable at December 31, 2004	6,525,224	$ 4.91	$ 23,817	4.9
Exercisable at December 31, 2005	4,417,331	$ 5.30	$ 34,985	4.3
Exercisable at December 31, 2006	6,814,387	$ 4.63	$ 46,829	4.9

(1) *The intrinsic value of a stock option is the amount by which the current market value of the underlying stock exceeds the exercise price of the option. The aggregate intrinsic value of stock options exercised during the years ended December 31, 2006, 2005 and 2004 was approximately $2.8 million, $44.0 million and $0.9 million, respectively.*

There were 500 options which expired in 2006, and none in 2005 or 2004. The weighted average grant date fair value of options granted in 2006 was $30.7 million. At December 31, 2006 the unrecognized compensation expense related to non-vested stock options totaled $5.1 million and will be recognized on a straight line basis over the weighted average remaining vesting period of 1.8 years.

In conjunction with the Company s merger with KCS, KCS stock options were converted into 2.6 million of Petrohawk stock options.

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The following table sets forth the restricted stock transactions for the years ended December 31, 2006, 2005 and 2004 (in thousands, except share and per share amounts).

	Number of Shares	Weighted Average Grant Date Fair Value Per Share	Aggregate Intrinsic Value [(1)]
Unvested outstanding shares at December 31, 2003		$	
Granted	45,000	8.25	
Unvested outstanding shares at December 31, 2004	45,000	$ 8.25	$ 385
Granted	100,000	10.31	
Vested	(71,666)	8.44	
Unvested outstanding shares at December 31, 2005	73,334	$ 10.87	$ 969
KCS shares assumed in merger	616,238	13.44	
Granted	888,888	11.72	
Vested	(116,121)	11.52	
Forfeited	(19,494)	10.72	
Unvested outstanding shares at December 31, 2006	1,442,845	$ 12.38	$ 16,593

(1) *The intrinsic value of restricted stock was calculated as the closing market price on December 31, 2006 of the underlying stock multiplied by the number of restricted shares. The intrinsic value of the shares vested for the year ended December 31, 2006 was $16.6 million.*

The weighted average grant date fair value of the shares granted in 2006 was $18.3 million. At December 31, 2006, the unrecognized compensation expense related to non-vested restricted stock totaled $10.4 million and will be recognized on a straight line basis over the weighted average remaining vesting period of 1.9 years.

In conjunction with the Company s merger with KCS, KCS restricted stock was converted into 0.6 million shares of Petrohawk restricted stock.

Earnings per Share

Basic earnings per share is calculated by dividing the income or loss available to common stockholders by the weighted average number of shares outstanding for the period. Diluted earnings per share reflects the potential dilution that could occur if securities or other contracts to issue common stock were exercised or converted into common stock.

401(k) Plan

The Company sponsors a 401(k) tax deferred savings plan, whereby the Company matches a portion of employees contributions in cash. Participation in the plan is voluntary and all regular employees of the Company are eligible to participate. The Company charged to expense plan contributions of $1.7 million in 2006, $0.7 million in 2005 and $0.3 million in 2004. The Company began matching employee contributions dollar-for-dollar on the first 10% of an employee s pretax earnings in September 2004. Prior contributions were matched dollar-for-dollar on the first 3% of an employee s pretax earnings.

Recently Issued Accounting Pronouncements

During July 2006, the FASB issued Financial Interpretation (FIN) No. 48, *Accounting for Uncertainty in Income Taxes an Interpretation of FASB Statement No. 109 (FIN 48).* FIN 48 addresses the accounting for uncertainty in income taxes recognized in an enterprise s financial statements in accordance with SFAS No. 109, *Accounting for Income Taxes*. FIN 48 prescribes specific criteria for the financial statement recognition and

measurement of the tax effects of a position taken or expected to be taken in a tax return. This interpretation also provides guidance on derecognition of previously recognized tax benefits, classification of tax liabilities on the balance sheet, recording interest and penalties on tax underpayments, accounting in interim periods, and disclosure requirements. FIN 48 is effective for fiscal periods beginning after December 15, 2006. The Company expects that the financial impact, if any, of applying the provisions of FIN 48 to all tax positions will not be material upon the initial adoption of FIN 48.

In December 2004, the FASB issued SFAS No. 123(R), *Share-Based Payment* (SFAS 123(R)). SFAS 123(R) revises SFAS No. 123, *Accounting for Stock-Based Compensation* (SFAS 123), and focuses on accounting for share-based payments for services provided by employee to employer. The statement requires companies to expense the fair value of employee stock options and other equity-based compensation at the grant date. The statement does not require a certain type of valuation model, and either a binomial or Black-Scholes model may be used. During the first quarter of 2005, the SEC approved a new rule for public companies to delay the adoption of this standard. In April 2005, the SEC took further action to amend Regulation S-X to state that the provisions of SFAS No. 123(R) will be effective beginning with the first annual or interim reporting period of the registrant s first fiscal year beginning on or after June 15, 2005 for all non-small business issuers. As a result, the Company did not adopt this SFAS until January 1, 2006. The Company used the modified prospective application method as detailed in SFAS No. 123(R). The adoption of this pronouncement did not materially impact the Company s operating results, financial position or cash flows. See Stock-Based Compensation above for further information.

In September 2006, the SEC Staff issued Staff Accounting Bulletin (SAB) No. 108, *Considering the Effects of Prior Year Misstatements when Quantifying Misstatements in Current Year Financial Statements*, in an effort to address diversity in the accounting practice of quantifying misstatements and the potential for improper amounts on the balance sheet. Prior to the issuance of SAB No. 108, the two methods used for quantifying the effects of financial statement errors were the roll-over and iron curtain methods. Under the roll-over method, the primary focus is the income statement, including the reversing effect of prior year misstatements. The criticism of this method is that misstatements can accumulate on the balance sheet. On the other hand, the iron curtain method focuses on the effect of correcting the ending balance sheet, with less importance on the reversing effects of prior year errors in the income statement. SAB No. 108 establishes a dual approach which requires the quantification of the effect of financial statement errors on each financial statement, as well as related disclosures. Public companies are required to record the cumulative effect of initially adopting the dual approach method in the first year ending after November 16, 2006 by recording any necessary corrections to asset and liability balances with an offsetting adjustment to the opening balance of retained earnings. The use of this cumulative effect transition method also requires detailed disclosures of the nature and amount of each error being corrected and how and when they arose. The adoption of this pronouncement did not materially impact the Company s operating results, financial position or cash flows.

2. ACQUISITIONS AND DIVESTITURES

Acquisitions

KCS Energy, Inc.

On April 21, 2006, the Company and KCS announced they had entered into a definitive agreement to merge the companies. This merger was consummated on July 12, 2006 and was consistent with management s goals of acquiring properties within the Company s core operating areas that have a significant proved reserve component and which management believes have additional development and exploration opportunities.

Upon the closing of the merger, KCS stockholders became entitled to receive a combination of $9.00 cash and 1.65 shares of Petrohawk common stock for each share of KCS common stock. At the time of the merger, there were approximately 50.0 million shares of unrestricted KCS common stock outstanding that converted into approximately 82.6 million shares of unrestricted Petrohawk common stock. Total consideration for the shares of KCS common stock was comprised of approximately $1.1 billion of Petrohawk common stock, calculated based

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on the five day average of Petrohawk s common stock around the merger announcement date, or $13.44, approximately $450 million of cash and the assumption of $275 million of KCS debt. In addition, all outstanding options to purchase KCS common stock and restricted shares of KCS common stock were converted into options to purchase the Company s common stock or restricted shares of the Company s common stock using an exchange ratio of approximately 2.3706 shares of Petrohawk common stock to one share of KCS common stock.

The merger was accounted for using the purchase method of accounting under the accounting standards established in SFAS No. 141, *Business Combinations* (SFAS 141) and SFAS 142. As a result, the assets and liabilities of KCS were first reported in the Company s September 30, 2006 consolidated balance sheet. The Company reflected the results of operations of KCS beginning July 12, 2006. The Company recorded the estimated fair values of the assets acquired and liabilities assumed at July 12, 2006, which primarily consisted of oil and natural gas properties of $1.6 billion, asset retirement obligations of $15.1 million, a deferred income tax liability of $421.6 million, a deferred income tax asset of $49.1 million and goodwill of $767.1 million. The deferred income tax liability recognizes the difference between the tax basis and the fair value of the acquired oil and natural gas properties. The recorded book value of the oil and natural gas properties was increased and goodwill was recorded to recognize this tax basis differential. The deferred income tax asset pertains to net operating loss carry-forwards and alternative minimum tax credits in the amounts of $44 million, net of tax, and $5.1 million, respectively.

North Louisiana Acquisitions

On January 27, 2006, the Company completed the acquisition of all of the issued and outstanding common stock of Winwell Resources, Inc. (Winwell). The aggregate consideration paid was approximately $208 million in cash after certain closing adjustments.

The Winwell acquisition was accounted for using the purchase method of accounting under the accounting standards established in SFAS 141 and SFAS 142. As a result, the assets and liabilities of Winwell were first reported in the Company s March 31, 2006 consolidated balance sheet. The Company reflected the results of operations of Winwell beginning January 27, 2006. The Company recorded the estimated fair values of the assets acquired and liabilities assumed at January 27, 2006, which primarily consisted of oil and natural gas properties of $219.8 million, asset retirement obligations of $0.5 million, a net deferred tax liability of $78.9 million, and goodwill of $33.5 million. The deferred tax liability recognizes the difference between the historical tax basis of Winwell s assets and the acquisition cost recorded for book purposes. The recorded book value of the oil and natural gas properties was increased and goodwill was recorded to recognize this tax basis differential.

Also on January 27, 2006, the Company completed the acquisition of certain oil and natural gas assets from Redley Company (together with the Winwell acquisition, the North Louisiana Acquisitions). The aggregate consideration paid in this asset acquisition was approximately $86.1 million ($86.2 million after certain closing adjustments). The Company reflected the results of operations of the acquired assets beginning January 27, 2006. The Company deposited $15 million in earnest money in connection with the Winwell acquisition, and $7.5 million in connection with the asset acquisition. The $22.5 million in deposits were included in other non-current assets at December 31, 2005 and applied to the overall purchase price in January 2006.

Mission Resources Corporation

On July 28, 2005, the Company and Mission Resources Corporation (Mission), completed a two-step merger transaction which resulted in Mission s merger with and into the Company. Total consideration for the shares of Mission common stock was comprised of 60.1% Company common stock and 39.9% cash. Accordingly, consideration paid to Mission stockholders consisted of approximately $139.5 million in cash and approximately 19.565 million shares of the Company s common stock. In addition, all outstanding options to purchase Mission common stock were converted into options to purchase Petrohawk common stock using the exchange ratio of 0.7641 shares of Petrohawk common stock per share of Mission common stock underlying each option. The Company assumed Mission s long-term debt of approximately $184 million.

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The Company s merger with Mission was accounted for using the purchase method of accounting under the accounting standards established in SFAS 141 and SFAS 142. As a result, the assets and liabilities of Mission were included in the Company s September 30, 2005 consolidated balance sheet. The Company reflected the results of operations of Mission beginning July 28, 2005. The Company recorded the estimated fair values of the assets acquired and liabilities assumed at July 28, 2005, which primarily consisted of oil and natural gas properties of $606.7 million, derivative liabilities of $29.4 million, asset retirement obligations of $37.7 million, a net deferred income tax liability of $134.8 million, and goodwill of $138.9 million. The deferred income tax liability recognizes the difference between the historical tax basis of Mission s assets and the acquisition cost recorded for book purposes. The recorded book value of the oil and natural gas properties was increased and goodwill was recorded to recognize this tax basis differential.

Pro Forma Results of Operations for the Company s Mergers with KCS and Mission

The Company s unaudited pro forma results of operations for the years ended December 31, 2006 and 2005 are presented below to illustrate the approximated pro forma effects on the Company s results of operations under the purchase method of accounting as if the Company had completed the mergers with KCS and Mission on January 1, 2005. The unaudited pro forma results of operations do not purport to represent what the results of operations would actually have been if the transactions had in fact occurred on such date or to project the Company s results of operations for any future date or period.

	For the Years Ended December 31, 2006 (Unaudited)	2005 (Unaudited)
	(In thousands, except per share amounts)	
Pro forma:		
Oil and gas sales	$ 813,138	$ 821,089
Net income (loss) available to common stockholders	194,463	(20,064)
Basic earnings (loss) per share	$ 1.17	$ (0.13)
Diluted earnings (loss) per share	$ 1.14	$ (0.13)

Other Transactions

Proton Oil & Gas Corporation

On February 25, 2005, the Company acquired the stock of Proton Oil & Gas Corporation (Proton) for $53 million in cash. This privately negotiated transaction had an effective date of January 1, 2005. The properties acquired were located in South Louisiana and South Texas.

The acquisition of Proton was accounted for using the purchase method of accounting. As a result, the assets and liabilities of Proton were included in the Company s March 31, 2005 consolidated balance sheet. The transaction had an effective date of January 1, 2005 and closed on February 25, 2005. As such, the Company reflected the results of operations of Proton beginning February 25, 2005. The Company recorded a purchase price of approximately $80.4 million of which $26.0 million reflected a non-cash item pertaining to the deferred income taxes attributable to the differences between the tax basis and the fair value of the acquired oil and natural gas properties. Substantially all of the $80.4 million was allocated to oil and natural gas properties.

Wynn-Crosby Transaction

On November 23, 2004, the Company acquired Wynn-Crosby Energy, Inc. and eight of the limited partnerships it managed for a purchase price of approximately $425 million after closing adjustments. The transaction was funded with proceeds from a $200 million private equity placement, $210 million in borrowings from its commercial bank group, and cash.

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PHAWK, LLC Transaction

On August 11, 2004, the Company acquired from PHAWK, LLC (formerly known as Petrohawk Energy, LLC) (PHAWK) certain oil and natural gas properties in the Breton Sound area, Plaquemines Parish, Louisiana and in the West Broussard field in Lafayette Parish, Louisiana. The purchase price for all of the proved reserves, seismic data, undeveloped acreage, pipelines, production facility and other assets was $8.5 million. The effective date of the acquisition was June 1, 2004 and the effects of this transaction were first reported in results for the quarter ended September 30, 2004. Refer to Note 10, *Related Party Transactions*, for more details.

Recapitalization by PHAWK, LLC

On May 25, 2004, PHAWK, LLC, which is owned by affiliates of EnCap Investments, L.P., Liberty Energy Holdings LLC, Floyd C. Wilson and other members of the Company s management, recapitalized the Company with $60 million in cash. The $60 million investment was structured as the purchase by PHAWK of 7.576 million new shares of common stock for $25 million, a $35 million five year 8% subordinated note convertible into approximately 8.75 million shares of common stock at a conversion price of $4.00 per share and warrants to purchase 5.0 million shares of common stock at a price of $3.30 per share. At the annual stockholders meeting held July 15, 2004, the stockholders approved changing the name of the Company to Petrohawk Energy Corporation (from Beta Oil & Gas, Inc.), reincorporating the Company in Delaware, and the adoption of new incentive plans. On June 30, 2005, the Company entered into an agreement with PHAWK, LLC to convert the PHAWK note to common stock as stipulated in the original agreement. Refer to Note 10, *Related Party Transactions*, for more details.

Divestitures

Michigan, Wyoming and California

During the fourth quarter of 2006 the Company sold certain of its oil and natural gas assets in Michigan, Wyoming and California. The majority of these assets were acquired in the Company s merger with KCS. Proceeds from these three separate transactions were approximately $135 million, before adjustments, and were recorded as a decrease to the Company s full cost pool.

Gulf of Mexico

On March 21, 2006, the Company completed the sale of substantially all of its Gulf of Mexico properties for $52.5 million ($43.2 million after certain closing adjustments). These proceeds were recorded as a decrease to the Company s full cost pool.

Royalty Interest Properties

On February 25, 2005, the Company completed the disposition of certain royalty interest properties previously acquired from Wynn-Crosby Energy, Inc. to Noble Royalties, Inc. d/b/a Brown Drake Royalties for approximately $80 million in cash. The proceeds from sale were recorded as a decrease to the Company s full cost pool.

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3. OIL AND NATURAL GAS PROPERTIES

Oil and natural gas properties as of December 31, 2006 and 2005 consisted of the following:

	December 31, 2006	December 31, 2005
	(In thousands)	
Subject to depletion	$ 2,901,649	$ 1,096,810
Not subject to depletion:		
Exploration wells in progress	6,020	14,006
Other capital costs:		
Incurred in 2006	457,889	
Incurred in 2005	44,728	113,215
Incurred in 2004 and prior	28,974	34,912
Total not subject to depletion	537,611	162,133
Gross oil and gas properties	3,439,260	1,258,943
Less accumulated depletion	(379,017)	(121,456)
Net oil and gas properties	$ 3,060,243	$ 1,137,487

The Company uses the full cost method of accounting for its investment in oil and natural gas properties. Under this method of accounting, all costs of acquisition, exploration and development of oil and natural gas reserves (including such costs as leasehold acquisition costs, geological expenditures, dry hole costs, tangible and intangible development costs and direct internal costs) are capitalized as the cost of oil and natural gas properties when incurred. To the extent that capitalized costs of oil and natural gas properties, net of accumulated depletion exceed the discounted future net revenues of proved oil and natural gas reserves net of deferred taxes, such excess capitalized costs would be charged to expense. Full cost companies must use the prices in effect at the end of each accounting quarter to calculate the ceiling test value of their reserves. However, subsequent commodity price increases may be utilized to calculate the ceiling value and reserves. At December 31, 2006, the ceiling test value of the Company s reserves was calculated based on the December 31, 2006 West Texas Intermediate posted price of $57.75 per barrel adjusted by lease for quality, transportation fees, and regional price differentials, and the December 31, 2006 Henry Hub spot market price of $5.63 per MMBtu adjusted by lease for energy content, transportation fees, and regional price differentials. Using these prices, the Company s net book value of oil and natural gas properties would have exceeded the ceiling amount by approximately $224 million (net of tax) at December 31, 2006. However, subsequent to year-end, the market price for Henry Hub gas and West Texas Intermediate oil increased significantly. As a consequence, prior to February 22, 2007, the Company elected to use prices on February 22, 2007, which were $7.51 per MMbtu for Henry Hub gas and $60.95 per barrel for West Texas Intermediate, adjusted for certain items as discussed above. Utilizing these prices, the Company s net book value of oil and natural gas properties at December 31, 2006 would not have exceeded the ceiling amount. As a result of the increase in the ceiling amount using the subsequent prices, the Company has not recorded a writedown of its oil and natural gas property costs. Decreases in product price levels, as well as changes in production rates, levels of reserves, the evaluation of costs excluded from amortization, future development costs, and service costs and other factors could result in significant future ceiling test impairments.

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4. LONG-TERM DEBT

Long-term debt as of December 31, 2006 and 2005 consisted of the following:

	December 31, 2006	December 31, 2005
	(In thousands)	
Senior revolving credit facility	$ 295,000	$ 210,000
Second lien term loan facility [(1)]		148,500
9 7/8% senior notes [(2)]	254	134,484
9 1/8% $650mm senior notes [(3)]	642,176	
9 1/8% $125mm senior notes [(4)]	126,338	
7 1/8% $275mm senior notes [(5)]	262,471	
Deferred premiums on derivatives [(6)]		2,817
	$ 1,326,239	$ 495,801

(1) *Amount excludes $1.5 million of the total facility which was classified as current at December 31, 2005. The facility was repaid in conjunction with the closing of the Company s merger with KCS. See Repayment of the Second Lien Term Loan Facility below for more details.*

(2) *The December 31, 2005 amount includes a $10 million premium recorded by the Company in conjunction with the assumption of $130 million face value of 9 7/8% notes payable from Mission which was written off in conjunction with the repayment of the notes in 2006. See 9 7/8% Senior Notes below for more details*

(3) *Amount includes a $7.8 million discount recorded by the Company in conjunction with the issuance of the notes. See 9 1/8% Senior Notes below for more details.*

(4) *Amount includes a $1.3 million premium recorded by the Company in conjunction with the issuance of the notes. See 9 1/8% Senior Notes below for more details.*

(5) *Amount includes a $12.5 million discount recorded by the Company in conjunction with the assumption of the notes. See 7 1/8% Senior Notes below for more details.*

(6) *Amount excludes $5.7 million and $1.3 million of deferred premiums on derivatives which have been classified as current at December 31, 2006 and 2005, respectively.*

Senior Revolving Credit Facility

In connection with the Company s merger with KCS, the Company amended and restated its senior revolving credit facility. The facility provides for a $1 billion commitment with a borrowing base that will be redetermined on a semi-annual basis. The Company and the lenders each have the right to one annual interim unscheduled redetermination to adjust the borrowing base based on the Company s oil and natural gas properties, reserves, other indebtedness and other relevant factors. At December 31, 2006, the borrowing base was $710 million. Amounts outstanding bear interest at specified margins over LIBOR of 1.00% to 1.75% for Eurodollar loans or at specified margins over ABR of 0.00% to 0.50% for ABR loans. Such margins fluctuate based on the utilization of the facility. Borrowings are secured by first priority liens on substantially all of the Company s assets and all of the assets of, and equity interest in, the Company s subsidiaries. Amounts drawn on the facility will mature on July 12, 2010.

The revolving credit facility contains customary financial and other covenants, including minimum working capital levels, minimum coverage of interest expense, and a maximum leverage ratio. In addition, the Company is subject to covenants limiting dividends and other restricted payments, transactions with affiliates, incurrence of debt, changes of control, asset sales, and liens on properties. At December 31, 2006, the Company is in compliance with all of its debt covenants under the revolving credit facility.

7 1/8% Senior Notes

Upon effectiveness of the Company s merger with KCS, the Company assumed (pursuant to the Second Supplemental Indenture relating to the 7 1/8% Senior Notes, also referred to as the 2012 Notes), and subsidiaries

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of the Company guaranteed (pursuant to the Third Supplemental Indenture relating to such notes), all the obligations (approximately $275 million) of KCS under the 2012 Notes and the Indenture dated April 1, 2004 (the 2012 Indenture) among KCS, U.S. Bank National Association, as trustee, and the subsidiary guarantors named therein, which governs the terms of the 7 1/8% senior notes due 2012. The 2012 Notes are guaranteed on an unsubordinated, unsecured basis by all of the Company s current subsidiaries, including the subsidiaries of KCS that the Company acquired in the merger. Interest on the 2012 Notes is payable semi-annually, on each April 1 and October 1. At any time prior to April 1, 2007, the Company may redeem up to 35% of the aggregate original principal amount of the 2012 Notes, using the net proceeds of equity offerings, at a redemption price equal to 107.125% of the principal amount of the 2012 Notes, plus accrued and unpaid interest. On or after April 1, 2008, the Company may redeem all or a portion of the 2012 Notes. If the notes are redeemed during any 12-month period beginning on April 1 of the year indicated below, the Company must pay 100% of the principal price, plus a specified premium (expressed as percentages of principal amount) plus accrued and unpaid interest thereon, if nay, to the applicable redemption date:

Year	Percentage
2008	103.568
2009	101.784
2010	100.000
2011	100.000
2012	100.000

The 2012 Indenture contains a provision requiring the Company to offer to purchase the 2012 Notes at 101% of face value in the event of a change of control (as defined in the 2012 Indenture). Certain 2012 Note holders have alleged that the merger constituted a change of control as set forth in the 2012 Indenture. Based upon consultation with counsel, the Company does not believe that a change of control occurred. See Note 6, *Commitments and Contingencies* for more details. At December 31, 2006, the Company is in compliance with all of its debt covenants under the 7 1/8% Senior Notes.

In conjunction with the assumption of the 7 1/8% Senior Notes from KCS, the Company recorded a discount of $13.6 million to be amortized over the remaining life of the notes utilizing the effective interest rate method. The remaining unamortized discount is $12.5 million at December 31, 2006.

The Notes are jointly and severally and fully and unconditionally guaranteed on a senior unsecured basis by all of the Company s current subsidiaries. Petrohawk Energy Corporation, the issuer of the Notes, has no material independent assets or operations apart from the assets and operations of its subsidiaries.

9 1/8% Senior Notes

On July 12, 2006, the Company consummated its private placement of 9 1/8% Senior Notes, also referred to as the 2013 Notes, pursuant to an Indenture dated as of July 12, 2006 (2013 Indenture) and the First Supplemental Indenture to the 2013 Notes (the 2013 First Supplemental Indenture), among the Company, the Company s subsidiaries named therein as guarantors, and U.S. Bank National Association, as trustee. The 2013 Notes were issued at 98.735% of the face amount for gross proceeds of approximately $642.0 million, before estimated offering expenses and the initial purchasers discount. The Company applied a portion of the net proceeds from the sale of the 2013 Notes to fund the cash consideration paid by the Company to the KCS stockholders in connection with the Company s merger with KCS and the Company s repurchase of the 9 7/8% Senior Notes due 2011 pursuant to a tender offer the Company concluded in July 2006.

The 2013 Notes bear interest at the rate of 9.125% per annum, payable semi-annually on January 15 and July 15 of each year, commencing January 15, 2007. The 2013 Notes mature on July 15, 2013. The 2013 Notes are senior unsecured obligations of the Company and rank equally with all of its current and future senior indebtedness, including the 2012 Notes. The 2013 Notes rank effectively subordinate to the Company s secured

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debt to the extent of the collateral, including secured debt under the revolving credit facility, and senior to any future subordinated indebtedness. The 2013 Notes are jointly and severally guaranteed on a senior unsecured basis by the Company s subsidiaries, including, pursuant to the 2013 First Supplemental Indenture, the KCS subsidiaries acquired in the Company s merger with KCS.

On or before July 15, 2009, the Company may redeem up to 35% of the aggregate principal amount of the 2013 Notes with the net cash proceeds of certain equity offerings at a redemption price of 109.13% of the principal amount plus accrued interest and unpaid interest to the redemption date provided that: (i) at least 65% in aggregate principal amount of the 2013 Notes originally issued under the 2013 Indenture remain outstanding immediately after the redemption (excluding 2013 Notes held by the Company and its subsidiaries); and (ii) each redemption must occur within 90 days of the date of the closing of the related equity offering.

In addition, on or before July 15, 2010, the Company may redeem all or part of the 2013 Notes upon not less than 30 nor more than 60 days notice, at a redemption price equal to the sum of (i) the principal amount, plus (ii) accrued and unpaid interest, if any, to the redemption date, plus (iii) the make whole premium at the redemption date.

On or after July 15, 2010, the Company may redeem some or all of the 2013 Notes at any time. If any of the 2013 Notes are redeemed during any 12-month period beginning on July 15 of the year indicated below, the Company must pay the following redemption prices (expressed as percentages of principal amount) plus accrued and unpaid interest thereon, if any, to the applicable redemption date:

Year	Percentage
2010	104.563
2011	102.281
2012	100.000

The Company may be required to offer to repurchase the 2013 Notes at a purchase price of 101% of the principal amount, plus accrued and unpaid interest, if any, to the redemption date, in the event of a change of control as defined in the 2013 Indenture. Additionally, the Company may be required to offer to repurchase the 2013 Notes and, to the extent required by the terms thereof, all other indebtedness (as defined in the 2013 Indenture) that is pari passu with the 2013 Notes at a purchase price of 100% of the principal amount (or accreted value in the case of any such other pari passu indebtedness issued with a significant original issue discount) plus accrued and unpaid interest, if any, to the date of purchase, in the event net proceeds from assets sales are not applied as required by the 2013 Indenture.

The 2013 Indenture contains covenants that, among other things, restrict or limit the ability of the Company and its subsidiaries to: (i) borrow money; (ii) pay dividends on stock; (iii) purchase or redeem stock or subordinated indebtedness; (iv) make investments; (v) create liens; (vi) enter into transactions with affiliates; (vii) sell assets; and (viii) merge with or into other companies or transfer all or substantially all of the Company s assets. Additionally, the Indenture covering the 2013 Notes contains a provision which provides for a rate increase of 1/8 of one percent if the Company refinances any part of its 2012 Notes on or before July 11, 2007.

The Company 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. The Company applied the net proceeds from the sale of the additional 2013 Notes to repay indebtedness outstanding under its revolving credit facility. At December 31, 2006, the Company is in compliance with all of its debt covenants relating to the 2013 Senior Notes.

In conjunction with the issuance of the $650 million 2013 Notes, the Company recorded a discount of $8.2 million to be amortized over the remaining life of the notes utilizing the effective interest rate method. The remaining unamortized discount was $7.8 million at December 31, 2006. In conjunction with the issuance of the

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$125 million 2013 Notes, the Company recorded a premium of $1.4 million to be amortized over the remaining life of the notes utilizing the effective interest rate method. The remaining unamortized premium was $1.3 million at December 31, 2006.

Repayment of the Second Lien Term Loan Facility

On July 12, 2006, in connection with its entry into the revolving credit facility and the closing of its sale of the 2013 Notes, the Company repaid all amounts outstanding under, and terminated, its Amended and Restated Second Lien Term Loan, dated as of July 28, 2005, between the Company, each of the Lenders from time to time party thereto and BNP Paribas, as administrative agent for the Lenders.

9 $^{7}/8$% Senior Notes

On April 8, 2004, Mission issued $130.0 million of its 9 $^{7}/8$% senior notes due 2011 (the 2011 Notes). The Company assumed these notes upon the closing of the Company s merger with Mission. In conjunction with the Company s merger with KCS, the Company extinguished substantially all of its 2011 Notes for a premium of $14.9 million plus accrued interest of $3.5 million. There were approximately $0.3 million of the notes which were not redeemed and are still outstanding as of December 31, 2006. In connection with the extinguishment of substantially all of the 2011 Notes, the Company requested and received from the noteholders consent to eliminate most significant debt covenants associated with the 2011 Notes.

Aggregate maturities required on long-term debt at December 31, 2006 are due in future years as follows (amounts in thousands):

2007	$
2008	
2009	
2010	295,000
2011	254
Thereafter	1,050,000
Total	$ 1,345,254

Debt Issuance Costs

The Company capitalizes certain direct costs associated with the issuance of long-term debt. At December 31, 2006, the Company has approximately $15.0 million of net debt issuance costs being amortized over the lives of the respective debt. Debt issuance costs increased $13.0 million from December 31, 2005 primarily due to the issuance of additional debt in the third quarter of 2006.

5. ASSET RETIREMENT OBLIGATION

If a reasonable estimate of the fair value of an obligation to perform site reclamation, dismantle facilities or plug and abandon wells can be made, the Company records a liability (an asset retirement obligation or ARO) on the consolidated balance sheet and capitalizes the asset retirement cost in oil and natural gas properties in the period in which the retirement obligation is incurred. In general, the amount of an ARO and the costs capitalized will be equal to the estimated future cost to satisfy the abandonment obligation using current prices that are escalated by an assumed inflation factor up to the estimated settlement date, which is then discounted back to the date that the abandonment obligation was incurred using an assumed cost of funds for the company. After recording these amounts, the ARO is accreted to its future estimated value using the same assumed cost of funds and the additional capitalized costs are depreciated on a unit-of-production basis.

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The Company recorded the following activity related to the ARO liability for the years ended December 31, 2006 and 2005 (in thousands):

Liability for asset retirement obligation as of January 1, 2005	$ 12,726
Liabilities settled and divested	(1,562)
Additions	455
Acquisitions [(1)]	38,473
Accretion expense	1,157
Liability for asset retirement obligation as of December 31, 2005	51,249
Liabilities settled and divested	(25,675)
Additions	2,223
Acquisitions [(1)]	15,985
Accretion expense	1,544
Liability for asset retirement obligation as of December 31, 2006	$ 45,326

[(1)] *Refer to Note 2 Acquisitions and Divestitures for more details on these acquisitions.*

6. COMMITMENTS, CONTINGENCIES AND LITIGATION
Contingencies

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. All known liabilities are accrued based on our best estimate of the potential loss. While the outcome and impact of currently pending legal proceedings cannot be predicted with certainty, our management and legal counsel believe that the resolution of these proceedings through settlement or adverse judgment will not have a material adverse effect on our consolidated financial position, results of operations or cash flow.

In connection with the KCS Merger, we assumed by operation of law all liabilities of KCS, including the 2012 Notes, which were originally issued by KCS in April 2004. U.S. Bank National Association served as Trustee under the indenture governing the 2012 Notes (the 2012 Indenture) from and after the date of issuance until October 13, 2006, when we believe it resigned.

Prior to the merger, we carefully considered the Change of Control provisions of the 2012 Indenture and, at the consummation of the merger, we concluded that the transaction did not trigger a Change of Control based upon the facts and the specific language of the 2012 Indenture. Consequently, we did not make a Change of Control Offer within 30 days of the merger.

On September 14, 2006, Law Debenture Trust Company of New York filed suit in the Court of Chancery of the State of Delaware, New Castle County, against us, members of our board of directors, certain of our officers, KCS and certain former members of the board of directors and past management of KCS, based on the assertion that a Change of Control occurred as a consequence of our merger with KCS and requesting, among other things, that we offer to repurchase the 2012 Notes at 101% face value. On October 9, 2006, we received a letter from Law Debenture alleging that an Event of Default had occurred as a result of our failure to make a Change of Control Offer. We filed a motion to dismiss Law Debenture s complaint arguing, among other things, that we had never received a valid Notice of Default. On November 22, 2006, Law Debenture sent us a letter again purporting to constitute a Notice of Default. On December 26, 2006, Law Debenture sent us a letter purporting to declare all unpaid principal, premium and interest due under the 2012 Notes due and payable in full. On December 27, 2006, Law Debenture served an amended complaint dropping all of the individual defendants from the suit and one of the claims it previously asserted against us and KCS. We have moved to dismiss the amended complaint, and briefing on the motion is underway. We intend to vigorously defend ourselves against these claims and to aggressively pursue all legal remedies available to us.

Prior to the acquisition of Mission Resources Corporation by the Company, Mission entered into agreements with a surety company and other third parties. All parties involved agreed to be jointly and severally liable to the surety company for certain liabilities arising under the agreement and limited to approximately $35 million. As of December 31, 2006, there have been no payments made, or liabilities recorded, as a result of these agreements.

Lease Commitments

The Company leases corporate office space in Houston, Texas and Tulsa, Oklahoma. In addition, the Company also has lease commitments related to certain vehicles, machinery and equipment under long-term operating leases. Rent expense was $2.0 million, $0.7 million and $0.3 million for the years ended December 31, 2006, 2005, and 2004, respectively. Future minimum lease payments for all non-cancelable operating leases are as follows (in thousands):

2007	$ 3,324
2008	3,104
2009	2,900
2010	2,890
2011	2,717
Thereafter	4,972
Total	$ 19,907

The Company also has 9 drilling rigs under contract. As of December 31, 2006, the Company is obligated over the next 4 years to pay $78.9 million as follows (in thousands):

2007	$ 45,724
2008	19,648
2009	11,788
2010	1,786
2011	
Thereafter	
Total	$ 78,946

7. DERIVATIVE AND HEDGING ACTIVITIES

Periodically, the Company enters into derivative commodity instruments to hedge its exposure to price fluctuations on anticipated oil and natural gas production. Under collar arrangements, if the index price rises above the ceiling price, the Company pays the counterparty. If the index price falls below the floor price, the counterparty pays the Company. Under price swaps, the Company is required to make payments to, or receive payments from, the counterparties based upon the differential between a specified fixed price and a price related to those quoted on the New York Mercantile Exchange for each respective period. Under put options, the Company pays a fixed premium to lock in a specified floor price. If the index price falls below the floor price, the counterparty pays the Company net of the fixed premium. If the index price rises above floor price, the Company pays the fixed premium.

At December 31, 2006, the Company had 94 open positions summarized in the tables below: 73 natural gas price collar arrangements, six natural gas price swap arrangements, two natural gas put options, two crude oil price swap arrangements and 11 crude oil collar arrangements. The Company elected not to designate any positions as cash flow hedges for accounting purposes, and accordingly, recorded the net change in the mark-to-market valuation of these derivative contracts in the consolidated statement of operations.

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At December 31, 2006, the Company had a $75.2 million derivative asset, $68.2 million of which is classified as current, and a $19.8 million derivative liability, $8.0 million of which is classified as current. The weighted average of the forward strip prices used to value the derivative liability were $65.40 per barrel of oil (Bbl) and $7.29 per million British thermal unit (MMBtu) of natural gas. The Company recorded a net derivative gain of $124.4 million ($10.0 million cash paid on settled contracts) for the year ended December 31, 2006.

At December 31, 2005, the Company had 48 open positions: 20 natural gas price collar arrangements, one natural gas price swap arrangement, four natural gas put options, one crude oil price swap arrangement and 22 crude oil collar arrangements. The Company elected not to designate any positions as cash flow hedges for accounting purposes, and accordingly, recorded the net change in the mark-to-market valuation of these derivative contracts in the consolidated statement of operations.

At December 31, 2005, the Company had a $3.5 million derivative asset, $1.3 million of which is classified as current, and an $86.8 million derivative liability, $51.1 million of which is classified as current. The weighted average of the forward strip prices used to value the derivative liability were $63.14 per Bbl of oil and $10.41 per MMBtu of natural gas. On the July 28, 2005 merger date, the Company acquired a $29.4 million derivative liability from Mission. At December 31, 2005, the fair value of the derivatives acquired from Mission was $22.7 million. The Company recorded a net derivative loss of $100.4 million for the year ended December 31, 2005.

At December 31, 2004, the Company had 90 open positions: 35 natural gas price collar arrangements, 12 natural gas price swap arrangements, seven natural gas put options, nine crude oil price swap arrangements and 27 crude oil collar arrangements. During 2004, the Company elected not to designate any positions as cash flow hedges for accounting purposes, and accordingly, recorded the change in mark-to-market valuation of these derivative contracts in the consolidated statement of operations.

At December 31, 2004, the Company had an $8.3 million derivative receivable and a $2.1 million derivative liability. In addition, the Company recorded a net derivative gain of $7.4 million for the year ended December 31, 2004.

Natural Gas

At December 31, 2006, the Company had the following natural gas costless collar positions:

		Collars			
		Floors		Ceilings	
Period	**Volume in MMBtu s**	**Price / Price Range**	**Weighted Average Price**	**Price / Price Range**	**Weighted Average Price**
January 2007 December 2007	55,385,000	$ 5.30 $9.00	$ 7.12	$ 7.12 $18.15	$ 11.55
January 2008 December 2008	20,980,000	5.00 8.00	6.75	6.45 19.15	11.05

At December 31, 2006, the Company had the following natural gas swap position:

		Swaps	
Period	**Volume in MMBtu s**	**Price / Price Range**	**Weighted Average Price**
January 2007 December 2007	3,455,000	$ 6.06 $8.87	$ 7.18

At December 31, 2006, the Company had the following natural gas put option positions:

	Floors	
Period	**Volume in MMBtu s**	**Weighted Average Price**
January 2007 December 2007	7,250,000	$ 8.00

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The Company has recorded a deferred premium liability of $5.7 million of long-term debt which has been classified as current at December 31, 2006 based on a weighted average deferred premium of $0.79 per MMBtu in 2007. The natural gas put option contracts contain deferred premiums that will be paid as the contracts expire.

Crude Oil

At December 31, 2006, the Company had the following crude oil costless collar positions:

		Collars			
		Floors		Ceilings	
Period	Volume in Bbls	Price / Price Range	Weighted Average Price	Price / Price Range	Weighted Average Price
January 2007 December 2007	1,736,000	$ 35.00 $70.00	$ 63.04	$ 43.20 $90.10	$ 81.53
January 2008 December 2008	792,000	34.00 70.00	64.96	45.30 85.05	80.26

At December 31, 2006, the Company had the following crude oil swap positions:

		Swaps	
Period	Volume in Bbls	Price / Price Range	Weighted Average Price
January 2007 December 2007	36,000	$ 63.85	$ 63.85
January 2008 December 2008	144,000	38.10	38.10

8. STOCKHOLDERS EQUITY

In conjunction with the Company s merger with KCS on July 12, 2006, the Company issued approximately 83.8 million shares of its common stock as consideration to the former stockholders of KCS. In 2005, the Company issued 19.6 million shares of common stock as merger consideration to holders of Mission stock.

In connection with the North Louisiana Acquisitions, on February 1, 2006, the Company issued and sold 13.0 million shares of its common stock for $14.50 per share, for an aggregate offering amount of approximately $188.5 million. The Company received approximately $180.4 million in net proceeds from the offering. Contemporaneously with the offering, the Company agreed to repurchase, and EnCap agreed to sell, approximately 3.3 million shares for $46.2 million, which represents the price equal to the net proceeds received for those 3.3 million shares by the Company from the private offering. These shares of common stock were privately placed in the offering and were not registered under the Securities Act of 1933, as amended (the Act), or any state securities laws. The common stock was offered and sold pursuant to the private placement exceptions from registration provided by Regulation D, Rule 506, under Section 4(2) of the Act and Regulation S of the Act. Shares of the common stock were offered and sold only to accredited investors (as defined in Rule 501(a) of the Act) and non-United States persons pursuant to the offers and sales outside the United States within the meaning of Regulation S under the Act. The placement agents for this offering received a cash payment of approximately $7.7 million as compensation for services provided in connection with the offering and to reimburse them for certain expenses. These shares were registered for resale on March 20, 2006 in conjunction with the filing of a Registration Statement on Form S-3 (No. 33-132565) in accordance with the terms of a registration rights agreement entered into by the Company.

Restricted Stock

In 2006, the Company granted 0.9 million shares of restricted common stock to employees and non-employee directors of the Company. These restricted shares were granted at prices ranging from $9.80 to $16.04 with a weighted average price of $11.72. Employee shares vest over a three-year period at a rate of one-third on the annual anniversary date of the grant and the directors shares cliff vest after a six-month period.

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In connection with the Company s merger with KCS, the Company converted legacy KCS restricted stock into 0.6 million shares of Petrohawk restricted stock on July 12, 2006. These shares cliff vest after a three-year period and expire ten years after the date of grant. The Company recognized $1.1 million in compensation cost for the year ended December 31, 2006 and will recognize $3.2 million in future periods related to these shares.

In 2005, the Company issued 0.1 million shares of restricted common stock to employees and non-employee directors of the Company. These restricted shares were granted at prices ranging from $8.51 to $11.00 with a weighted average price of $10.31. Employee shares vest over a three-year period at a rate of one-third on the annual anniversary date of the grant and the directors shares cliff vest after a six-month period.

Performance Shares

In conjunction with the Company s merger with KCS, the Company adopted a plan under which performance share awards are granted under the KCS 2005 Plan (defined below). Performance awards contain a contingent right to receive shares of common stock. The grantee would earn between 0% and 200% of the target amount of performance shares upon the achievement of pre-determined objectives over a three-year performance period. The objectives relate to the Company s total stockholder return (as defined in the form of performance share agreement) as compared to the total stockholder return of a group of peer companies during the performance period. The Company does not anticipate the issuance of any additional performance share awards in future periods.

The fair value of the awards using a Monte Carlo technique was $10.89 per share. The Company will recognize compensation cost of $1.5 million over the expected service life of the performance share awards whether or not the threshold is achieved. The Company recognized $0.3 million in compensation cost for the period between the Company s merger with KCS and December 31, 2006.

Warrants and Options

The number of shares reserved for the exercise of common stock purchase warrants and stock options under the Company s Incentive Plans (as defined below) as of December 31, 2006 is 9.23 million at a weighted average price of $6.34, as detailed in the table in Note 1.

Warrants and options outstanding at December 31, 2006 consisted of the following:

	Outstanding Warrants and Options			Exercisable Options	
Range of Exercise Prices Per Share	Number of Options	Weighted Average Exercise Price per share	Weighted Average Remaining Contractual Life (Years)	Number of Options	Weighted Average Exercise Price per share
$ 0.50 3.80	4,330,923	$ 2.77	3.5	4,330,923	$ 2.77
4.06 6.18	594,586	5.30	7.0	545,230	5.28
6.60 11.00	3,287,156	9.01	8.3	1,827,881	8.37
11.08 19.00	1,013,854	13.52	8.6	110,353	12.32

During the second quarter of 2004, and in connection with the recapitalization of the Company by PHAWK, LLC transaction, the Company issued PHAWK, LLC 5 million five-year common stock purchase warrants at a price of $3.30 per share. The warrants are exercisable at any time and expire on May 25, 2009. On August 31, 2005, 2.3 million warrants were exercised. The exercise was cashless, reducing number of shares issued by the value of the $3.30 exercise price, so that the Company issued 1.6 million shares of company stock. On July 8, 2005, shares and warrants held by PHAWK, LLC were distributed to its members, including certain members of our management.

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Incentive Plans

The Company s Incentive Plans include the Second Amended and Restated 2004 Employee Incentive Plan (2004 Employee Plan), Second Amended and Restated 2004 Non-Employee Director Incentive Plan (2004 Non-Employee Director Plan), Mission Resources Corporation 1994 Stock Incentive Plan (Mission 1994 Plan), Mission Resources Corporation 1996 Stock Incentive Plan (Mission 1996 Plan) and Mission Resources Corporation 2004 Stock Incentive Plan (Mission 2004 Plan), KCS Energy, Inc. 2001 Employee and Directors Stock Plan (KCS 2001 Plan) and the KCS Energy, Inc. 2005 Employee and Directors Stock Plan (KCS 2005 Plan) as of December 31, 2006.

2004 Employee Incentive Plan

Upon stockholder approval and effective July 28, 2005, the Company s Amended and Restated 2004 Employee Incentive Plan was amended and restated to be the Second Amended and Restated 2004 Employee Incentive Plan (the 2004 Plan) to increase the aggregate number of shares that can be issued under the 2004 Plan from 2.75 million to 4.25 million. The 2004 Plan permits the Company to grant to management and other employees shares of common stock with no restrictions, shares of common stock with restrictions, and options to purchase shares of common stock.

On July 12, 2006, the Company and its stockholders approved an amendment to the 2004 Plan to increase the number of shares available for issuance thereunder from 4.25 million shares to 7.05 million shares.

In 2006, the Company granted stock options covering 1.88 million shares of common stock to employees of the Company. The options have exercise prices ranging from $9.80 to $16.04 with a weighted average price of $11.94. These options vest over a three year period at a rate of one-third on the annual anniversary date of the grant and expire ten years from the grant date.

In connection with the Company s merger with KCS, the Company converted legacy KCS stock options into a total of 2.59 million Petrohawk stock options on July 12, 2006. These options vest over a three-year period and expire ten years after the date of grant. Weighted average grant date fair value of the options was determined to be $9.81 per share, using the Black-Scholes fair value method. The Company recognized $0.9 million in compensation cost for the year ended December 31, 2006 and will recognize $1.2 million in future periods related to these options.

In 2005, the Company granted stock options covering 1.40 million shares of common stock to employees of the Company. The options vest over a three-year period with one-third vesting on the date of grant, one-third one year from the date of the grant and the remaining one-third two years from the date of the grant. The options have exercise prices ranging from $0.52 to $11.52 with a weighted average price of $9.37. These options expire ten years from the grant date.

In 2004, the Company granted stock options out of the 2004 Plan covering 0.72 million shares of common stock to employees of the Company. The options will vest over a two-year period with one-third vesting on the date of grant, one-third in one year from the date of the grant and the remaining one-third in two years from the date of the grant. The options have an average exercise price of $7.53 per share and will expire ten years from the date of grant.

For the years ended December 31, 2006, 2005 and 2004, respectively, the Company has recognized $8.2 million, $3.8 million and $3.5 million respectively, of non-cash stock compensation expense.

At December 31, 2006, 2.50 million options were available under the Plan for future issuance.

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2004 Non-Employee Director Incentive Plan

In July 2004 the Company adopted the 2004 Non-Employee Director Plan covering 0.20 million shares. The plan provides for the grant of both incentive stock options and restricted shares of the Company s stock. This plan was designed to attract and retain the services of directors. At the adoption of the plan each non-employee director received 7,500 restricted shares of the Company s common stock and each new non-employee director would receive 7,500 shares of the Company s common stock. Additional grants of 5,000 restricted shares of the Company s common stock were issued to each non-employee director on each anniversary of his or her service. These shares vest over a six month period from the date of grant. Shares were issued under this plan for the years-ended December 31, 2006, 2005 and 2004, were 72,500 shares, 45,000 shares and 45,000 shares, respectively and there had been no forfeited or cancelled shares.

On July 12, 2006, the Company and its stockholders approved an amendment to the Company s 2004 Non-Employee Director Plan to increase the number of shares available for issuance thereunder from 0.4 million to 0.6 million shares. At December 31, 2006, 0.44 million options were available under the Plan for future issuance.

KCS and Mission Incentive Plans

Upon consummation of the Company s merger with KCS, the Company assumed the KCS 2001 Plan, as amended, the KCS 2005 Plan, as amended, and associated obligations relating to grants of restricted stock, stock options and performance shares under those plans which were granted prior to the closing of the Company s merger with KCS. At December 31, 2006, 7.77 million Petrohawk options were available under the Plan for future issuance.

In conjunction with the Merger on July 28, 2005, the Company assumed three incentive plans related to Mission Resources. The three plans were the Mission 1994 Plan, Mission 1996 Plan and Mission 2004 Plan. At December 31, 2006, there were 0.3 million Petrohawk options available under these plans for future issuance.

8% Cumulative Convertible Preferred Stock

On June 29, 2001 the Company completed its Private Placement Offering of 8% cumulative convertible preferred stock and common stock purchase warrants, offered as units of one preferred share and one-half of one warrant at $9.25 per unit. Net proceeds received from the offering were approximately $5.0 million net of estimated offering expenses, including brokers commissions and other fees and expenses of $0.5 million. The Company issued 0.6 million preferred shares and 0.15 million warrants to purchase a like number of shares of the Company s common stock at a price equal to the offering price or $9.25 per share. Brokers were issued 29,888 non-callable warrants as part of their commission. All investors participating in the offering were accredited. The proceeds were used by the Company to help meet its capital requirements, including drilling costs and for other general corporate purposes.

In April 2006, the Company initiated a buyback of the preferred stock for $9.25 per unit. On June 9, 2006, the Company sent the holders of the preferred shares notice of redemption as set forth in the certificate of designation for the preferred stock. On July 10, 2006, the Company completed the redemption of the preferred stock. As of December 31, 2006, there were no remaining preferred shares outstanding. All Class A and Class B warrants associated with the preferred stock expired on June 29, 2006.

Series B Preferred Stock

In connection with the acquisition of Wynn-Crosby on November 23, 2004, the Company issued and sold 2.58 million shares of Series B 8% Automatically Convertible Preferred Stock (Series B Preferred Stock) for $77.50 per share, for an aggregate offering amount of approximately $200 million. The Company received

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approximately $185 million in net proceeds from the offering. The Series B Preferred Stock was offered and sold pursuant to the private placement exception from registration provided in Regulation D, Rule 506, under Section 4(2) of the Act. Shares of the Series B preferred stock were offered and sold only to qualified institutional buyers as defined in Rule 144A of the Act with whom the placement agent had pre-existing relationships in reliance on applicable exemptions from registration provided under the Act. The placement agent received a commission of 6.0% in connection with the offering.

On December 31, 2004 each outstanding share of the Series B Preferred Stock converted into ten shares of common stock. Accordingly, 2.6 million shares of the Company s Series B Preferred Stock converted into 25.8 million shares of common stock.

Treasury Stock

In August 2004, the Company s Board of Directors terminated the stock repurchase program. During the quarter ended September 30, 2006, the Company retired its 8,382 treasury shares.

9. INCOME TAXES

Income tax (provision) benefit for the indicated periods is comprised of the following:

	Years Ended December 31,		
	2006	2005	2004
		(In thousands)	
Current:			
Federal	$ (2,069)	$ (217)	$ 24
State	(65)	(253)	
	(2,134)	(470)	24
Deferred:			
Federal	(66,337)	9,088	(641)
State	(4,064)	445	(512)
	(70,401)	9,533	(1,153)
Total (provision) benefit	$ (72,535)	$ 9,063	$ (1,129)

The actual income tax (provision) benefit differs from the expected tax (provision) benefit as computed by applying the U.S. Federal corporate income tax rate of 35% for each period as follows:

	Years Ended December 31,		
	2006	2005	2004
		(In thousands)	
Amount of expected tax (provision) benefit	$ (66,184)	$ 8,994	$ (3,144)
State taxes, net	(3,818)	625	(338)
Valuation allowance	(191)	(500)	2,352
Other	(2,342)	(56)	1
Total (provision) benefit	$ (72,535)	$ 9,063	$ (1,129)

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The components of net deferred tax assets and liabilities recognized are as follows:

	December 31, 2006	December 31, 2005
	(In thousands)	
Deferred current tax assets:		
Unrealized hedging transactions	$	$ 18,304
Deferred current tax assets	$	$ 18,304
Deferred current tax liabilities:		
Unrealized hedging transactions	$ (22,382)	$
Deferred current tax liabilities	$ (22,382)	$
Deferred noncurrent tax assets:		
Net operating loss carry-forwards	$ 112,175	$ 45,825
Stock-based compensation expense	4,189	2,596
Unrealized hedging transactions	3,772	12,294
Alternative minimum tax credit carryforwards	7,368	217
Other	(2,312)	94
Gross deferred noncurrent tax assets	125,192	61,026
Valuation allowance	(692)	(500)
Net deferred noncurrent tax assets	$ 124,500	$ 60,526
Deferred noncurrent tax liabilities:		
Book-tax differences in property basis	$ (758,383)	$ (213,681)
Net long-term deferred tax liabilities	$ (633,883)	$ (153,155)

As of December 31, 2006, the Company had available, to reduce future taxable income, a U.S. federal regular net operating loss (NOL) carryforward of approximately $309.3 million, and a U.S. federal alternative minimum tax NOL carryforward of approximately $44.5 million, which expire in the years 2017 through 2024. Utilization of NOL carryforwards is subject to annual limitations due to stock ownership changes. The tax net operating loss carryforward may be limited by other factors as well. The Company also has various state NOL carryforwards, reduced by the valuation allowance for losses that the Company anticipates will expire before they can be utilized, totaling approximately $66.5 million at December 31, 2006, with varying lengths of allowable carryforward periods ranging from five to 20 years that can be used to offset future state taxable income. It is expected that these deferred tax benefits will be utilized prior to their expiration.

10. RELATED PARTY TRANSACTIONS

On May 25, 2004, PHAWK, LLC (formerly known as Petrohawk Energy, LLC) (PHAWK), which is owned by affiliates of EnCap Investments, L.P., Liberty Energy Holdings LLC, Floyd C. Wilson and other members of the Company s management, purchased a controlling interest in the Company for $60 million in cash. The $60 million investment was structured as the purchase by PHAWK of 7.576 million shares of common stock for $25 million, a $35 million five year 8% subordinated note convertible into approximately 8.75 million shares of common stock and warrants to purchase 5 million shares of common stock at a price of $3.30 per share (after giving effect to a one-for-two reverse split of the Company s common stock implemented in May 2004). In connection with the investment by PHAWK, Mr. Wilson was named Chairman, President and Chief Executive Officer, the Company s board of directors and other management was changed, and the corporate offices were relocated from Tulsa, Oklahoma to Houston, Texas. Also, at the annual stockholders meeting held July 15, 2004, the Company s stockholders approved changing the name of the company to Petrohawk Energy Corporation (from Beta Oil & Gas, Inc.), reincorporating the company in Delaware, and the adoption of new stock option plans.

On June 30, 2005, the Company entered into an agreement with PHAWK to convert the Company s $35 million note payable to PHAWK to common stock as stipulated in the original agreement. The original agreement contained a provision providing for conversion into 8.75 million shares of Petrohawk common stock at any time after May 25, 2006. In consideration of the early conversion, the Company agreed to make a payment of $2.4 million, which represented the interest payable on the note through May 25, 2006, discounted at 10%. In conjunction with the conversion, the Company expensed $1.1 million of net debt issuance costs that were being amortized over the remaining life of the note. These charges are reflected in interest expense and other on the consolidated statement of operations.

A Special Committee of one disinterested director was formed by the Company s board of directors to evaluate the transaction. On June 30, 2005, the Special Committee approved the transaction.

On August 11, 2004 the Company purchased working interests in certain oil and natural gas properties and various other assets from PHAWK for $8.5 million. The effective date of the acquisition was June 1, 2004. Since the Company and PHAWK were under common control, the assets were recorded by the Company at the net book value of PHAWK at the time of the sale. The purchase price exceeded the net book value by approximately $5.6 million. The excess was reflected as a return of capital to PHAWK on the consolidated statement of operations.

A special committee of one disinterested director was formed by the Company s board of directors to evaluate, negotiate and complete the purchase. The Special Committee hired an independent reservoir engineering firm to provide a reserve evaluation and engaged an independent financial advisor to evaluate the fairness, from a financial point of view, to the Company. The independent financial advisor rendered a fairness opinion to the Special Committee.

In February 2006, the Company repurchased approximately 3.3 million shares of its common stock held by EnCap Investments, L.P., and certain of its affiliates, at a price per share equal to the net proceeds per share that the Company received from a private offering of 13.0 million of its common shares that closed on the same day as the EnCap purchase. The 3.3 million shares were repurchased for $46.2 million.

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11. NET INCOME (LOSS) PER COMMON SHARE

The following represents the calculation of net income (loss) per common share (in thousands, except per share data):

	Years Ended December 31, 2006	2005	2004
	(In thousands, except per share amounts)		
Basic			
Net income (loss)	$ 116,563	$ (16,634)	$ 8,117
Less: preferred dividends	(217)	(440)	(445)
Net income (loss) available to common stockholders	$ 116,346	$ (17,074)	$ 7,672
Weighted average number of shares	122,452	54,752	10,808
Basic earnings (loss) per share	$ 0.95	$ (0.31)	$ 0.71
Diluted			
Net income (loss)	$ 116,346	$ (17,074)	$ 7,672
Plus: preferred dividends	217		445
Plus: Interest on 8% subordinated convertible note payable (net of tax)			1,072
Net income (loss) available to common stockholders	$ 116,563	$ (17,074)	$ 9,189
Weighted average number of shares	122,452	54,752	10,808
Common stock equivalent shares representing shares issuable upon exercise of stock options	989	Anti-dilutive	327
Common stock equivalent shares representing shares issuable upon exercise of warrants	1,251	Anti-dilutive	2,826
Common stock equivalent shares representing shares included upon vesting of restricted shares	1,443	Anti-dilutive	
Common stock equivalent shares representing shares as-if conversion of note payable		Anti-dilutive	8,750
Common stock equivalent shares representing shares as-if conversion of preferred shares		Anti-dilutive	2,979
Weighted average number of shares used in calculation of diluted income (loss) per share	126,135	54,752	25,690
Diluted earnings (loss) per share	$ 0.92	$ (0.31)	$ 0.36

The following common stock equivalents were not included in the computation for diluted earnings (loss) per share because their effects would be antidilutive.

Common Stock Equivalents:	Years Ended December 31, 2006	2005	2004
	(In thousands)		
Options	894	2,779	99
Warrants	18	2,919	805
As-if conversion of Preferred stock		294	
	912	5,992	904

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12. ADDITIONAL FINANCIAL STATEMENT INFORMATION

Certain balance sheet amounts are comprised of the following:

	December 31, 2006	2005
	(In thousands)	
Accounts receivable:		
Oil and gas sales	$ 107,003	$ 48,369
Joint interest accounts	37,056	15,954
Income taxes receivable	5,453	
Other	6,070	3,764
	$ 155,582	$ 68,087
Accounts payable and accrued liabilities:		
Trade payables	$ 31,565	$ 16,379
Revenues and royalties payable to others	69,383	22,273
Accrued capital costs	111,252	23,610
Accrued interest expense	40,906	3,664
Accrued lease operating expenses	10,601	5,854
Accrued ad valorem taxes payable	7,086	2,690
Accrued employee compensation	2,649	1,610
Other	22,509	13,937
	$ 295,951	$ 90,017

Certain cash and non-cash related items:

	Years Ended December 31, 2006	2005	2004
		(In thousands)	
Cash payments:			
Interest payments	$ 43,714	$ 26,507	$ 2,766
Income tax payments	$ 4,847	$ 24	$
Non-cash items excluded from the statement of cash flows:			
Accrued capital expenditures	$ 87,642	$ 6,005	$ 1,915

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SUPPLEMENTAL OIL AND GAS INFORMATION (UNAUDITED)

Oil and Natural Gas Reserves

Users of this information should be aware that the process of estimating quantities of proved and proved developed oil and natural gas reserves is very complex, requiring significant subjective decisions in the evaluation of all available geological, engineering and economic data for each reservoir. The data for a given reservoir may also change substantially over time as a result of numerous factors including, but not limited to, additional development activity, evolving production history and continual reassessment of the viability of production under varying economic conditions. As a result, revisions to existing reserve estimates may occur from time to time. Although every reasonable effort is made to ensure reserve estimates reported represent the most accurate assessments possible, the subjective decisions and variances in available data for various reservoirs make these estimates generally less precise than other estimates included in the financial statement disclosures.

Proved reserves represent estimated quantities of natural gas, crude oil and condensate that geological and engineering data demonstrate, with reasonable certainty, to be recoverable in future years from known reservoirs under economic and operating conditions in effect when the estimates were made. Proved developed reserves are proved reserves expected to be recovered through wells and equipment in place and under operating methods used when the estimates were made.

Estimates of proved reserves at December 31, 2006 and 2005 were prepared by Netherland, Sewell & Associates, Inc. (Netherland, Sewell), the Company s independent consulting petroleum engineers. The December 31, 2004 proved reserve estimates were prepared by Netherland, Sewell with the exception of 26.2 Bcfe of proved reserves associated with royalty interest properties acquired from Wynn-Crosby and subsequently sold on February 25, 2005 which were not part of Netherland, Sewell s report. All proved reserves are located in the United States of America.

The following table illustrates the Company s estimated net proved reserves, including changes, and proved developed reserves for the periods indicated, as estimated by Netherland, Sewell. Natural gas liquids are included in oil reserves. Oil and natural gas liquids are based on the December 31, 2006 West Texas Intermediate posted price of $57.75 per barrel and are adjusted by lease for quality, transportation fees, and regional price differentials. Gas prices are based on a December 31, 2006 Henry Hub spot market price of $5.63 per MMBtu and are adjusted by lease for energy content, transportation fees, and regional price differentials. All prices are held constant in accordance with SEC guidelines.

		Proved Reserves	
	Oil (MBbls)	Gas (MMcf)	Equivalent (MMcfe)
Proved reserves, January 1, 2004	1,308	22,400	30,245
Extensions and discoveries	93	3,902	4,458
Purchase of minerals in place	8,205	138,835	188,064
Production	(244)	(3,569)	(5,030)
Revision of previous estimates	339	(690)	1,347
Proved reserves, December 31, 2004	9,701	160,878	219,084
Extensions and discoveries	1,409	19,905	28,359
Purchase of minerals in place	20,285	111,079	232,789
Production	(1,555)	(20,219)	(29,549)
Sale of minerals in place	(2,723)	(12,670)	(29,008)
Revision of previous estimates	2,115	2,904	15,594
Proved reserves, December 31, 2005	29,232	261,877	437,269

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	Proved Reserves		
	Oil (MBbls)	Gas (MMcf)	Equivalent (MMcfe)
Extensions and discoveries	4,379	268,906	295,180
Purchase of minerals in place	9,015	482,762	536,852
Production	(3,203)	(60,642)	(79,863)
Sale of minerals in place	(7,024)	(37,677)	(79,821)
Technical revisions	(775)	5,790	1,140
Price revisions	(460)	(31,880)	(34,637)
Proved reserves, December 31, 2006	31,164	889,136	1,076,120

	Proved Developed Reserves		
	Oil (Mbls)	Gas (MMcf)	Equivalent (MMcfe)
December 31, 2004	8,504	119,733	170,756
December 31, 2005	22,398	177,603	311,990
December 31, 2006	23,188	534,561	673,688

Capitalized Costs Relating to Oil and Natural Gas Producing Activities

The following table illustrates the total amount of capitalized costs relating to oil and natural gas producing activities and the total amount of related accumulated depreciation, depletion and amortization (in thousands).

	December 31,		
	2006	2005	2004
Evaluated properties	$ 2,903,763	$ 1,098,553	$ 485,251
Unevaluated properties	537,611	162,133	49,547
	3,441,374	1,260,686	534,798
Accumulated depreciation, depletion and amortization	(379,984)	(122,301)	(49,473)
	$ 3,061,390	$ 1,138,385	$ 485,325

Costs Incurred in Oil and Natural Gas Property Acquisition, Exploration and Development Activities

The Costs Incurred in Oil and Natural Gas Property Acquisition, Exploration and Development Activities table has been restated to combine asset retirement costs with Property acquisition costs, proved and Development costs.

Costs incurred in property acquisition, exploration and development activities were as follows (in thousands):

	Years Ended December 31,					
	2006		2005		2004	
	Previously Reported	As Restated	Previously Reported	As Restated	Previously Reported	As Restated
Property acquisition costs, proved	$ 1,390,504	$ 1,406,489	$ 562,499	$ 600,972	$ 387,063	$ 397,888
Property acquisition costs, unproved	517,695	517,695	107,664	107,664	50,423	50,423
Exploration and extension well costs	337,076	337,076	35,083	35,083	5,972	5,972
Development costs	150,112	152,335	67,457	67,912	5,395	5,936
Asset retirement costs	18,208		38,928		11,366	

Total costs	$ 2,413,595	$ 2,413,595	$ 811,631	$ 811,631	$ 460,219	$ 460,219

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Standardized Measure of Discounted Future Net Cash Flows Relating to Proved Oil and Natural Gas Reserves

The following information has been developed utilizing SFAS 69, *Disclosures about Oil and Gas Producing Activities*, (SFAS 69) procedures and based on oil and natural gas reserve and production volumes estimated by the Company s engineering staff. It can be used for some comparisons, but should not be the only method used to evaluate the Company or its performance. Further, the information in the following table may not represent realistic assessments of future cash flows, nor should the Standardized Measure of Discounted Future Net Cash Flow be viewed as representative of the current value of the Company.

The Company believes that the following factors should be taken into account when reviewing the following information:

future costs and selling prices will probably differ from those required to be used in these calculations;

due to future market conditions and governmental regulations, actual rates of production in future years may vary significantly from the rate of production assumed in the calculations;

a 10% discount rate may not be reasonable as a measure of the relative risk inherent in realizing future net oil and natural gas revenues; and

future net revenues may be subject to different rates of income taxation.

Under the Standardized Measure, future cash inflows were estimated by applying year-end oil and natural gas prices to the estimated future production of year-end proved reserves. Estimates of future income taxes are computed using current statutory income tax rates including consideration for estimated future statutory depletion and tax credits. The resulting net cash flows are reduced to present value amounts by applying a 10% discount factor. Use of a 10% discount rate and year-end prices are required by SFAS 69.

The Standardized Measure of Discounted Future Net Cash Flows Relating to Proved Oil and Natural Gas Reserves table has been restated to correct the amount of future income tax expense recognized and correct the methodology utilized in the discount calculation including consideration of the annual impact of income taxes in future periods.

The Standardized Measure is as follows (in thousands):

	Years Ended December 31,					
	2006		2005		2004	
	Previously Reported	As Restated	Previously Reported	As Restated	Previously Reported	As Restated
Future cash inflows	$ 6,492,900	$ 6,492,900	$ 3,636,669	$ 3,636,669	$ 1,347,069	$ 1,347,069
Future production costs	(1,703,787)	(1,703,787)	(988,796)	(988,796)	(376,814)	(376,814)
Future development costs	(1,044,147)	(1,044,147)	(255,800)	(255,800)	(78,825)	(78,825)
Future net cash flows before income taxes	3,744,966	3,744,966	2,392,073	2,392,073	891,430	891,430
Future income tax expense	(827,000)	(1,004,896)	(620,660)	(669,018)	(171,148)	(171,201)
Future net cash flows before 10% discount	2,917,966	2,740,070	1,771,413	1,723,055	720,282	720,229
10% annual discount for estimated timing of cash flows	(1,734,085)	(1,170,023)	(1,029,372)	(699,336)	(337,265)	(307,359)
	$ 1,183,881	$ 1,570,047	$ 742,041	$ 1,023,719	$ 383,017	$ 412,870

Standardized measure of discounted future net cash flows

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Changes in Standardized Measure of Discounted Future Net Cash Flows Relating to Proved Oil and Natural Gas Reserves

The Changes in Standardized Measure of Discounted Future Net Cash Flows Relating to Proved Oil and Natural Gas Reserves table has been restated to correct Changes in income taxes, net and add Development costs incurred in addition to line items miscalculated in our Annual Report on Form 10-K for the fiscal year ended December 31, 2006, originally filed on February 28, 2007.

The following is a summary of the changes in the Standardized Measure of discounted future net cash flows for the Company s proved oil and natural gas reserves during each of the years in the three year period ended December 31, 2006 (in thousands).

	Years Ended December 31,					
	2006		2005		2004	
	Previously Reported	As Restated	Previously Reported	As Restated	Previously Reported	As Restated
Beginning of year	$ 742,041	$ 1,023,719	$ 383,017	$ 412,870	$ 48,333	$ 48,333
Sale of oil and gas produced, net of production costs	(84,180)	(459,881)	(257,622)	(203,463)	(25,219)	(25,398)
Purchase of minerals in place	1,484,511	1,484,511	695,811	695,811	476,716	476,716
Sales of minerals in place	(284,411)	(265,315)	(71,585)	(71,585)	(162)	(162)
Extensions and discoveries	340,975	353,392	148,154	148,154	13,196	13,196
Changes in income taxes, net	(110,795)	(84,094)	(256,222)	(288,240)	(71,488)	(65,224)
Changes in prices and costs	(817,917)	(486,834)	222,188	286,069	(20,183)	(14,247)
Development costs incurred		(152,335)		(67,912)		(5,936)
Revisions of previous quantities	(28,961)	(48,142)	(147,275)	53,179	(65,451)	(65,451)
Accretion of discount	136,270	225,683	47,470	79,868	4,833	10,443
Changes in production rates and other	(193,652)	(20,657)	(21,895)	(21,032)	22,442	40,600
End of year	$ 1,183,881	$ 1,570,047	$ 742,041	$ 1,023,719	$ 383,017	$ 412,870

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SELECTED QUARTERLY FINANCIAL DATA (UNAUDITED)

The following table presents selected quarterly financial data derived from the Company s consolidated financial statements. The following data is only a summary and should be read with the Company s historical consolidated financial statements and related notes contained in this document. The acquisition of KCS in 2006 and of Mission in 2005 affects the comparability between the consolidated financial data for the periods presented.

	Quarters Ended			
	March 31	June 30	September 30	December 31
	(In thousands, except per share amounts)			
2006				
Oil and gas sales	$ 103,006	$ 86,414	$ 196,439	$ 201,903
Income from operations	36,430	18,364	50,691	49,055
Net income[(1)]	32,939	4,853	52,656	26,115
Earnings per share of common stock:				
Basic	$ 0.40	$ 0.06	$ 0.34	$ 0.16
Diluted	$ 0.39	$ 0.06	$ 0.33	$ 0.15
2005				
Oil and gas sales	$ 32,326	$ 36,184	$ 81,447	$ 108,082
Income from operations	9,030	11,427	34,018	49,415
Net (loss) income[(1)]	(14,252)	(2,202)	(36,424)	36,244
(Loss) earnings per share of common stock:				
Basic	$ (0.36)	$ (0.06)	$ (0.56)	$ 0.49
Diluted	$ (0.36)	$ (0.06)	$ (0.56)	$ 0.48

(1) *The volatility in net income (loss) is substantially due to the Company s accounting policy to mark derivative positions to market and not apply cash flow hedge accounting. See Note 7, Derivative and Hedging Activity for additional information.*

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ITEM 9. CHANGES IN AND DISAGREEMENTS WITH ACCOUNTANTS ON ACCOUNTING AND FINANCIAL DISCLOSURE

None.

ITEM 9A. CONTROLS AND PROCEDURES

Management s Evaluation of Disclosure Controls and Procedures

In accordance with Exchange Act Rules 13a-15 and 15d-15, we carried out an evaluation, under the supervision and with the participation of management, including our Chief Executive Officer and our Chief Financial Officer, of the effectiveness of our disclosure controls and procedures as of the end of the period covered by this report. Based on that evaluation, our Chief Executive Officer and Chief Financial Officer concluded that our disclosure controls and procedures were effective as of December 31, 2006 to provide reasonable assurance that information required to be disclosed in our reports filed or submitted under the Exchange Act is recorded, processed, summarized and reported within the time periods specified in the Securities and Exchange Commission s rules and forms.

Management s Report on Internal Control over Financial Reporting

Management s report on internal control over financial reporting as of December 31, 2006 can be found on page 46 of the Financial Section of this report.

Management s assessment of the effectiveness of internal control over financial reporting as of December 31, 2006, was audited by Deloitte & Touche LLP, an independent registered public accounting firm, as stated in their report which is included on page 47 of the Financial Section of this report.

Changes in Internal Control over Financial Reporting

There has been no change in our internal control over financial reporting that occurred during the three months ended December 31, 2006 that has materially affected, or is reasonably likely to materially affect, our internal control over financial reporting.

ITEM 9B. OTHER INFORMATION

None.

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PART IV

ITEM 15. EXHIBITS AND FINANCIAL STATEMENT SCHEDULES

(1) Consolidated Financial Statements:
The consolidated financial statements of the Company and its subsidiaries and report of independent public accountants listed in Section 8 of this Form 10-K/A are filed as a part of this Form 10-K/A.

(2) Consolidated Financial Statements Schedules:
All schedules are omitted because they are inapplicable or because the required information is contained in the financial statements or included in the notes thereto.

(3) Exhibits:
The following documents are included or incorporated as exhibits to this Form 10-K/A.

Exhibit No.	Description
2.1	Agreement and Plan of Merger, dated April 3, 2005 (and as amended through June 8, 2005), by and among Petrohawk Energy Corporation, Petrohawk Acquisition Corporation, and Mission Resources Corporation (Incorporated by reference to Annex A of our Registration Statement on Form S-4/A filed on June 22, 2005).
2.2	Agreement and Plan of Merger, dated October 13, 2004, among Petrohawk Energy Corporation, Wynn-Crosby Energy, Inc., Ronald W. Crosby and Paige L. Crosby (Incorporated by reference to Exhibit 2.1 of our Current Report on Form 8-K filed on November 24, 2004).
2.3	Agreement and Plan of Mergers, dated October 13, 2004, among Petrohawk Energy Corporation, Wynn-Crosby Energy, Inc., Wynn-Crosby 1994, Ltd.; Wynn-Crosby 1995, Ltd.; Wynn-Crosby 1996, Ltd.; Wynn-Crosby 1997, Ltd.; Wynn-Crosby 1998, Ltd.; Wynn-Crosby 1999, Ltd.; Wynn-Crosby 2000, Ltd.; Wynn-Crosby 2002, Ltd.; WCOG Properties, Ltd.; Kara Nicole Limited; Kristen Lee Limited; Eric Wynn Limited; Christopher David Limited; Paige Lee Limited; Bernadien Wynn Limited; Roger Lee Limited; and George Heaps Limited, and Ronald W. Crosby (Incorporated by reference to Exhibit 2.2 of our Current Report on Form 8-K filed on November 24, 2004).
2.4	Amendment to Agreement and Plan of Mergers among Petrohawk Energy Corporation, Wynn-Crosby Energy, Inc., Wynn-Crosby 1994, Ltd.; Wynn-Crosby 1995, Ltd.; Wynn-Crosby 1996, Ltd.; Wynn-Crosby 1997, Ltd.; Wynn-Crosby 1998, Ltd.; Wynn-Crosby 1999, Ltd.; Wynn-Crosby 2000, Ltd.; Wynn-Crosby 2002, Ltd.; WCOG Properties, Ltd.; Kara Nicole Limited; Kristen Lee Limited; Eric Wynn Limited; Christopher David Limited; Paige Lee Limited; Bernadien Wynn Limited; Roger Lee Limited; and George Heaps Limited, and Ronald W. Crosby, dated October 26, 2004 (Incorporated by reference to Exhibit 2.3 of our Current Report on Form 8-K filed on November 24, 2004).
2.5	Stock Purchase Agreement among Winwell Resources, Inc. and all of its Shareholders, as Sellers, and Petrohawk Energy Corporation, as Buyer, dated as of December 14, 2005 (Incorporated by reference to Exhibit 2.1 of our Current Report on Form 8-K filed December 20, 2005).
2.6	Asset Purchase Agreement among Redley Company, Burris Run Company and Red Clay Minerals, collectively as Seller, and Petrohawk Energy Corporation, as Buyer, dated as of December 14, 2005 (Incorporated by reference to Exhibit 2.2 of our Current Report on Form 8-K filed December 20, 2005).
2.7	First Amendment to Asset Purchase Agreement among Redley Company, Burris Run Company and Red Clay Minerals, collectively as Seller, and Petrohawk Energy Corporation, as Buyer, effective as of December 14, 2005 (Incorporated by reference to Exhibit 2.7 of our Annual Report on Form 10-K filed March 14, 2006).

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Exhibit No.	Description
2.8	Assignment Agreement between Petrohawk Properties, L.P. and Petrohawk Energy Corporation effective January 27, 2006 (Incorporated by reference to Exhibit 2.8 of our Annual Report on Form 10-K filed March 14, 2006).
2.9	Purchase and Sale Agreement executed January 14, 2005, by and between Wynn-Crosby 1994, Ltd., et al and Noble Royalties, Inc. d/b/a Brown Drake Royalties (Incorporated by reference to Exhibit 2.1 to our Current Report on Form 8-K filed on March 3, 2005).
2.10	Amendment to Purchase and Sale Agreement executed on February 15, 2005, by and between Wynn-Crosby 1994, Ltd., et al and Noble Royalty, Inc. d/b/a Brown Drake Royalties (Incorporated by reference to Exhibit 2.2 to our Current Report on Form 8-K filed on March 3, 2005).
2.11	Stock Purchase Agreement dated February 4, 2005 by and among Petrohawk Energy Corporation and Proton Oil & Gas Corporation, et al (Incorporated by reference to Exhibit 2.3 to our Current Report on Form 8-K filed on March 3, 2005).
2.12	Purchase and Sale Agreement between Petrohawk Energy Corporation and Petrohawk Properties, LP, together, as Seller, and Northstar GOM, LLC, as Buyer, dated February 3, 2006 (Incorporated by reference to Exhibit 2.1 to our Current Report on Form 8-K filed February 9, 2006).
2.13	Amended and Restated Agreement and Plan of Merger executed as of May 16, 2006, and effective as of April 20, 2006 by and among KCS Energy, Inc., Petrohawk Energy Corporation and Hawk Nest Corporation (Incorporated by reference to Exhibit 2.1 of our Current Report on Form 8-K filed May 18, 2006).
3.1	Certificate of Incorporation for Petrohawk Energy Corporation (Incorporated by reference to Exhibit 3.1 to our Form S-8 filed on July 29, 2004).
3.2	Certificate of Amendment to Certificate of Incorporation for Petrohawk Energy Corporation (Incorporated by reference to Exhibit 3.1 of our Current Report on Form 8-K filed on November 24, 2004).
3.3	Certificate of Amendment of Certificate of Incorporation of Petrohawk Energy Corporation (Incorporated by reference to Exhibit 3.1 of our Current Report on Form 8-K filed on August 3, 2005).
3.6	Amended and Restated Bylaws of Petrohawk Energy Corporation effective as of July 12, 2006 (Incorporated by reference to Exhibit 3.2 of our Current Report on Form 8-K filed on July 17, 2006).
3.7	Certificate of Amendment to Certificate of Incorporation of Petrohawk Energy Corporation (Incorporated by reference to Exhibit 3.1 of our Current Report on Form 8-K filed on July 17, 2006).
4.15	Indenture dated April 1, 2004 among KCS Energy, Inc., U.S. Bank National Association, as trustee, and the subsidiary guarantors named therein, relating to KCS Energy, Inc. s 7 1/8% senior notes due 2012 (Incorporated by reference to Exhibit 4.1 to KCS Energy, Inc. s Quarterly Report on Form 10-Q filed on May 10, 2004.)
4.16	First Supplemental Indenture, dated as of April 8, 2005, to Indenture dated as of April 1, 2004, among KCS Energy, Inc., certain of its subsidiaries and U.S. Bank National Association (Incorporated by reference to Exhibit 4.1 of KCS Energy, Inc. s Form 8-K filed on April 11, 2005.)
4.17	Second Supplemental Indenture dated July 12, 2006 among Petrohawk Energy Corporation, the successor by way of merger to KCS Energy, Inc., the parties named therein as guarantors, and U.S. Bank National Association, as trustee (Incorporated by reference to Exhibit 4.4 to our Current Report on Form 8-K filed July 17, 2006).

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Exhibit No.	Description
4.18	Third Supplemental Indenture dated as of July 12, 2006 among Petrohawk Energy Corporation, the successor by way of merger to KCS Energy, Inc., the parties named therein as existing guarantors, the parties named therein as new guarantors, and U.S. Bank National Association, as trustee (Incorporated by reference to Exhibit 4.5 to our Current Report on Form 8-K filed July 17, 2006).
4.19	Indenture dated July 12, 2006 among Petrohawk Energy Corporation, U.S. Bank National Association, as trustee, and the subsidiary guarantors named therein, relating to Petrohawk Energy Corporation s 9 1/8 % senior notes due 2013 (Incorporated by reference to Exhibit 4.6 to our Current Report on Form 8-K filed July 17, 2006).
4.20	First Supplemental Indenture dated July 12, 2006 among Petrohawk Energy Corporation, U.S. Bank National Association, as trustee, and the subsidiary guarantors named therein (Incorporated by reference to Exhibit 4.7 to our Current Report on Form 8-K filed July 17, 2006).
4.21	Registration Rights Agreement dated July 12, 2006 among Petrohawk Energy Corporation, the Guarantors named therein, and the Initial Purchasers named therein (Incorporated by reference to Exhibit 4.3 to our Registration Statement on Form S-4 filed September 1, 2006)
4.22	Registration Rights Agreement dated July 12, 2006 among Petrohawk Energy Corporation, the Guarantors named therein, and the Initial Purchasers named therein (Incorporated by reference to Exhibit 4.4 to our Registration Statement on Form S-4 filed September 1, 2006).
10.1	The Petrohawk Energy Corporation Amended and Restated 1999 Incentive and Nonstatutory Stock Option Plan (Incorporated by reference to Exhibit 99.3 of our Current Report on Form 8-K filed on August 18, 2004).
10.2	The Petrohawk Energy Corporation Second Amended and Restated 2004 Non-Employee Director Incentive Plan (Incorporated by reference to Exhibit 4.1 to our Registration Statement No. 333-117733 on Form S-8 filed July 29, 2005).
10.3	Form of Stock Option Agreement for the Second Amended and Restated 2004 Non-Employee Director Incentive Plan (Incorporated by reference to Exhibit 10.3 to our Quarterly Report on Form 10-Q filed August 11, 2005).
10.4	Form of Restricted Stock Agreement for the Second Amended and Restated 2004 Non-Employee Director Incentive Plan (Incorporated by reference to Exhibit 10.4 of our Second Quarter 2005 Form 10-Q filed on August 11, 2005).
10.5	Form of Incentive Stock Agreement for the Second Amended and Restated 2004 Non-Employee Director Incentive Plan (Incorporated by reference to Exhibit 10.5 of our Second Quarter 2005 Form 10-Q filed on August 11, 2005).
10.6	The Petrohawk Energy Corporation Second Amended and Restated 2004 Employee Incentive Plan (Incorporated by reference to Exhibit 4.2 to our Registration Statement No. 333-117733 on Form S-8 filed July 29, 2005).
10.7	Form of Stock Option Agreement for the Second Amended and Restated 2004 Employee Incentive Plan (Incorporated by reference to Exhibit 10.3 of our Annual Report on Form 10-K filed March 14, 2006).
10.8	Form of Restricted Stock Agreement for the Second Amended and Restated 2004 Employee Incentive Plan (Incorporated by reference to Exhibit 10.8 of our Second Quarter 2005 Form 10-Q filed on August 11, 2005).
10.9	Form of Incentive Stock Agreement for the Second Amended and Restated 2004 Employee Incentive Plan (Incorporated by reference to Exhibit 10.9 of our Second Quarter 2005 Form 10-Q filed on August 11, 2005).

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Exhibit No.	Description
10.10	Mission Resources Corporation 1994 Stock Incentive Plan (Incorporated by reference to Exhibit 10.9 of Mission Resources Corporation s Registration Statement No. 33-76570 filed on March 17, 1994).
10.11	Mission Resources Corporation 1996 Stock Incentive Plan (Incorporated by reference to Exhibit A of Mission Resources Corporation s Proxy Statement on Schedule 14A filed on October 21, 1996).
10.12	Mission Resources Corporation 2004 Incentive Plan (Incorporated by reference to Appendix C to Mission Resources Corporation s Proxy Statement on Schedule 14A filed on March 30, 2004).
10.15	Form of Director and Officer Indemnity Agreement (Incorporated by reference to Exhibit 10.11 of our Annual Report on Form 10-K filed on March 31, 2005).
10.18	Stock Purchase Agreement between Petrohawk Energy Corporation and EnCap Investments, L.P., *et al*., effective as of January 10, 2006 (Incorporated by reference to Exhibit 10.30 of our Annual Report on Form 10-K filed on March 14, 2006).
10.23	Second Amended and Restated Senior Revolving Credit Agreement dated July 12, 2006, among Petrohawk Energy Corporation, each of the Lenders from time to time party thereto, BNP Paribas, as administrative agent for the lenders, Bank of America, N.A. and BMO Capital Markets Financing, Inc., as co-syndication agents for the Lenders, and JPMorgan Chase Bank, N.A., Wells Fargo Bank, N.A. and Fortis Capital Corp., as co-documentation agents for the Lenders (Incorporated by reference to Exhibit 10.3 to our Current Report on Form 8-K filed July 17, 2006).
10.24	Amended and Restated Guarantee and Collateral Agreement dated July 12, 2006, made by Petrohawk Energy Corporation and each of its subsidiaries, as Grantors, in favor of BNP Paribas, as Administrative Agent (Incorporated by reference to Exhibit 10.4 to our Current Report on Form 8-K filed July 17, 2006).
10.25	First Amendment to Second Amended and Restated Senior Revolving Credit Agreement, dated as of July 12, 2006, between Petrohawk Energy Corporation, each of the lenders from time to time party thereto, BNP Paribas, as administrative agent for the lenders, Bank of America, N.A. and BMO Capital Markets Financing, Inc. as co-syndication agents for the lenders, and JPMorgan Chase Bank, N.A., Wells Fargo Bank, N.A. and Fortis Capital Corp. as co-documentation agents for the lenders (Incorporated by reference to Exhibit 10.1 to our Current Report on Form 8-K filed July 28, 2006).
10.26	First Amendment to the Petrohawk Energy Corporation Second Amended and Restated 2004 Employee Incentive Plan (Incorporated by reference to Exhibit 10.7 to our Quarterly Report on Form 10-Q filed August 9, 2006).
10.27	First Amendment to the Petrohawk Energy Corporation Second Amended and Restated 2004 Non-Employee Director Incentive Plan (Incorporated by reference to Exhibit 10.8 to our Quarterly Report on Form 10-Q filed August 9, 2006).
10.28	KCS Energy, Inc. 2001 Employee and Directors Stock Plan (Incorporated by reference to Exhibit (10)iii to KCS Energy, Inc. s Annual Report on Form 10-K filed April 2, 2001), as amended by the Amendment to the KCS Energy, Inc. 2001 Employee and Directors Stock Plan (Incorporated by reference to Exhibit 10.4 to KCS Energy, Inc. s Current Report on Form 8-K filed April 25, 2006).
10.29	Form of Supplemental Stock Option Agreement under KCS Energy, Inc. 2001 Employee and Directors Stock Plan (Incorporated by reference to Exhibit 10.6 of KCS Energy, Inc s Quarterly Report on Form 10-Q filed November 9, 2004).
10.30	Form of Directors Supplemental Stock Option Agreement under KCS Energy, Inc. 2001 Employee and Directors Stock Plan (Incorporated by reference to Exhibit 10.7 of KCS Energy, Inc. s Quarterly Report on Form 10-Q filed November 9, 2004).

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Exhibit No.	Description
10.31	Form of Restricted Stock Award Agreement under KCS Energy, Inc. 2001 Employee and Directors Stock Plan (Incorporated by reference to Exhibit 10.8 of KCS Energy, Inc. s Quarterly Report on Form 10-Q filed November 9, 2004).
10.32	Form of Restricted Stock Award Agreement (with accelerated vesting provision) under 2001 KCS Energy, Inc. Employee and Directors Stock Plan (Incorporated by reference to Exhibit 10.9 of KCS Energy, Inc. s Quarterly Report on Form 10-Q filed November 9, 2004).
10.33	KCS Energy, Inc. 2005 Employee and Directors Stock Plan (Incorporated by reference to Exhibit 4.8 to KCS Energy, Inc s Registration Statement on Form S-8 (File No. 333-125690) filed June 10, 2005), as amended by the First Amendment to KCS Energy, Inc. 2005 Employee and Directors Stock Plan (Incorporated by reference to Exhibit 10.1 to KCS Energy, Inc. s Current Report on Form 8-K filed May 19, 2005).
10.34	Form of Supplemental Stock Option Agreement under KCS Energy, Inc. 2005 Employee and Directors Stock Plan and related Stock Option Exercise Agreement (Incorporated by reference to Exhibit 10.3 of KCS Energy, Inc. s Current Report on Form 8-K filed June 16, 2005).
10.35	Form of Supplemental Stock Option Agreement for Non-Employee Directors under KCS Energy, Inc. 2005 Employee and Directors Stock Plan (Incorporated by reference to Exhibit 10.4 of KCS Energy, Inc s Current Report on Form 8-K filed June 16, 2005).
10.36	Form of Restricted Stock Award Agreement under KCS Energy, Inc. 2005 Employee and Directors Stock Plan (without accelerated vesting provision) and related Restricted Stock Award Certificate (Incorporated by reference to Exhibit 10.5 of KCS Energy, Inc s Current Report on Form 8-K filed June 16, 2005).
10.37	Form of Restricted Stock Award Agreement under KCS Energy, Inc. 2005 Employee and Directors Stock Plan (with accelerated vesting provision) and related Restricted Stock Award Certificate (Incorporated by reference to Exhibit 10.6 of KCS Energy, Inc. s Current Report on Form 8-K filed June 16, 2005).
10.38	Form of Amended and Restated Performance Share Award Certificate under KCS Energy, Inc. 2005 Employee and Directors Stock Plan (Incorporated by reference to Exhibit 10.19 to our Quarterly Report on Form 10-Q filed November 3, 2006).
10.39	Form of Amendment to Restricted Stock Agreement under the KCS Energy, Inc. 2001 Employee and Directors Stock Plan (Incorporated by reference to Exhibit 10.5 to KCS Energy, Inc. s Current Report on Form 8-K filed April 25, 2006).
10.40	Form of Amendment to Supplemental Stock Option Agreement under KCS Energy, Inc. s 2001 Employee and Directors Stock Plan (Incorporated by reference to Exhibit 10.5 to KCS Energy, Inc. s Current Report on Form 8-K filed April 25, 2006).
10.41	Executive Employment Agreement Form A for certain executives and Petrohawk Energy Corporation (incorporated by reference to the exhibit of the same number filed with the Registrants Annual Report on Form 10-K filed with the SEC on February 28, 2007).
10.42	Executive Employment Agreement Form B for certain executives and Petrohawk Energy Corporation (incorporated by reference to the exhibit of the same number filed with the Registrants Annual Report on Form 10-K filed with the SEC on February 28, 2007).
10.43	Amendment No. 2 to the KCS Energy, Inc. 2005 Employees and Directors Stock Plan (incorporated by reference to the exhibit of the same number filed with the Registrants Annual Report on Form 10-K filed with the SEC on February 28, 2007).
10.44	Amendment No. 2 to the KCS Energy, Inc. 2001 Employees and Directors Stock Plan (incorporated by reference to the exhibit of the same number filed with the Registrants Annual Report on Form 10-K filed with the SEC on February 28, 2007).

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Exhibit No.	Description
10.45	Amendment No. 1 to the Mission Resources Corporation 1996 Stock Incentive Plan (incorporated by reference to the exhibit of the same number filed with the Registrants Annual Report on Form 10-K filed with the SEC on February 28, 2007).
12.1	Computation of Ratio of Earnings to Combined Fixed Charges and Preference Dividends (incorporated by reference to the exhibit of the same number filed with the Registrants Annual Report on Form 10-K filed with the SEC on February 28, 2007).
14.1	Code of Ethics (Incorporated by reference to Exhibit D of the Definitive Proxy on Schedule 14A filed on June 23, 2004).
21.1	Subsidiaries of the Registrant (incorporated by reference to the exhibit of the same number filed with the Registrants Annual Report on Form 10-K filed with the SEC on February 28, 2007).
23.1*	Consent of Deloitte & Touche LLP
23.2*	Consent of Netherland, Sewell & Associates, Inc.
31.1*	Certificate of Chief Executive Officer under Section 302 of the Sarbanes-Oxley Act of 2002
31.2*	Certificate of Chief Financial Officer under Section 302 of the Sarbanes-Oxley Act of 2002
32*	Certifications required by Rule 13a-14(b) or Rule 15d-14(b) under the Securities and Exchange Act of 1934 and 18 U.S.C. Section 1350.
99.1	Netherland, Sewell & Associates, Inc. Reserve Report

* Exhibits designated by the symbol * are filed with this Annual Report on Form 10-K/A. All exhibits not so designated are incorporated by reference to a prior filing with the SEC as indicated

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

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SIGNATURES

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

PETROHAWK ENERGY CORPORATION

Date: June 1, 2007

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

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the registrant and in the capacities and on the dates indicated.

Signature	Title	Date
/s/ Floyd C. Wilson **Floyd C. Wilson**	Chairman of the Board, President and Chief Executive Officer	June 1, 2007
/s/ Shane M. Bayless **Shane M. Bayless**	Executive Vice President, Chief Financial Officer and Treasurer	June 1, 2007
/s/ Mark J. Mize **Mark J. Mize**	Vice President, Chief Accounting Officer and Controller	June 1, 2007
/s/ James W. Christmas **James W. Christmas**	Vice Chairman and Director	June 1, 2007
/s/ Tucker S. Bridwell **Tucker S. Bridwell**	Director	June 1, 2007
/s/ Thomas R. Fuller **Thomas R. Fuller**	Director	June 1, 2007
/s/ James L. Irish, III **James L. Irish, III**	Director	June 1, 2007
/s/ Gary A. Merriman **Gary A. Merriman**	Director	June 1, 2007
/s/ Robert G. Raynolds **Robert G. Raynolds**	Director	June 1, 2007

/s/ ROBERT C. STONE, JR. **Robert C. Stone, Jr.**	Director	June 1, 2007
/s/ CHRISTOPHER A. VIGGIANO **Christopher A. Viggiano**	Director	June 1, 2007