CRIMSON EXPLORATION INC.
Form 10-K
April 02, 2007

UNITED STATES

SECURITIES AND EXCHANGE COMMISSION

WASHINGTON, D.C. 20549

FORM 10-K

x	ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934 For the fiscal year ended December 31, 2006 OR
o	TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934

For the transition period from ____________ to ____________

Commission file number: 000-21644

CRIMSON EXPLORATION INC.

(Exact name of registrant as specified in its charter)

Delaware (State or other jurisdiction of incorporation or organization)	**20-3037840** (I.R.S. Employer Identification No.)
480 N. Sam Houston Parkway East, Suite 300	
Houston, Texas (Address of principal executive offices)	**77060** (Zip Code)

(281) 820-1919

(Registrant s telephone number, including area code)

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

Securities registered pursuant to Section 12(g) of the Act: Common Stock, $0.001 par value per share

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

Indicate by check mark if the registrant is not required to file reports pursuant to Section 13 or Section 15(d) of the Exchange Act. Yes o 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 (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. Yes x No o

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

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

Large accelerated filer o Accelerated filer o Non-accelerated filer x

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

As of June 30, 2006, the aggregate market value of the registrant s common stock held by non-affiliates of the registrant was $6,531,699 based on the closing sales price of $6.80 of the common stock. For purposes of this computation, all executive officers, directors and 10% beneficial owners of the registrant are deemed to be affiliates. Such a determination should not be deemed an admission that such executive officers, directors and 10% beneficial owners are affiliates.

On March 19, 2007, there were 3,338,749 shares of common stock outstanding.

DOCUMENTS INCORPORATED BY REFERENCE

Portions of our Definitive Proxy Statement for the 2007 Annual Meeting, expected to be filed within 120 days of our fiscal year end, are incorporated by reference into Part III.

FORWARD-LOOKING STATEMENTS

Certain terms that we use in our industry are italicized and defined in the Glossary of Industry Terms and Abbreviations . Unless otherwise indicated, all references to Crimson , GulfWest , the Company , we , us and our refer to Crimson Exploration Inc. and our subsidiaries.

We make forward-looking statements throughout this Annual Report within the meaning of Section 27A of the Securities Act of 1933, as amended, and Section 21E of the Securities Exchange Act of 1934, as amended.

These forward-looking statements include, but are not limited to, statements regarding:

- *estimates of proved reserve quantities and net present values of those reserves;*
- *estimates of probable and possible reserve quantities;*
- *reserve potential;*
- *business strategy;*
- *estimates of future commodity prices;*
- *amounts and types of capital expenditures and operating expenses;*
- *expansion and growth of our business and operations;*
- *expansion and development trends of the oil and natural gas industry;*
- *production of oil and natural gas reserves;*
- *exploration prospects;*
- *wells to be drilled, and drilling results;*
- *operating results and working capital; and*
- *future methods and types of financing.*

Whenever you read a statement that is not simply a statement of historical fact (such as when we describe what we believe, expect or anticipate will occur, and other similar statements), you must remember that our expectations may not be correct, even though we believe they are reasonable. We do not guarantee that the transactions and events described in this Annual Report will happen as described (or that they will happen at all). The forward-looking information contained in this Annual Report is generally located in the material set forth under the headings Business , Risk Factors , and Management s Discussion and Analysis of Financial Condition and Results of Operations but may be found in other locations as well. These forward-looking statements generally relate to our plans and objectives for future operations and are based upon our management s reasonable estimates of future results and trends.

PART I

ITEM 1. Business

Our Business

We are primarily engaged in the acquisition, development, exploitation and production of crude oil and natural gas, primarily in the onshore producing regions of the United States. Our focus is on increasing production from our existing properties through further exploitation, development and exploration, and on acquiring additional interests in undeveloped crude oil and natural gas properties.

Since we made our first significant acquisition in 1993, we have substantially increased our ownership in *producing properties* and our crude oil and natural gas reserves through a combination of acquisitions and the further exploitation and development of our properties. At December 31, 2006, our part of the estimated *proved reserves* these properties contained was approximately 2.5 million barrels (*MBbl*) of oil and 31.4 billion cubic feet (*Bcf*) of natural gas with an estimated *Net Present Value discounted at 10% (PV-10)* of $102.4 million. At present,

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all of our properties are located on land in Texas, Colorado, Louisiana and Mississippi, except for the property in the shallow inland boundaries of Grand Lake, Louisiana. In the future, we plan to expand by acquiring additional properties in those areas, and in similar properties located in other producing regions of the United States, including the shallow waters of the Gulf of Mexico.

Our gross revenues are derived from the following sources:

1. **Oil and gas sales** that are proceeds from the sale of crude oil and natural gas production to midstream purchasers. This represents over 99% of our gross revenues.
2. **Operating overhead and other income** that consists of administrative fees received for operating crude oil and natural gas properties for other working interest owners and for marketing and transporting natural gas for those owners. This also includes earnings from other miscellaneous activities.

Our operations are considered to fall within a single industry segment, which is the acquisition, development, production and servicing of crude oil and natural gas properties. See Item 7. Management s Discussion and Analysis of Financial Condition and Results of Operations.

Our Common Stock is traded over-the-counter (OTC) under the symbol CXPO .

Our Company

We were formed as a corporation under the laws of the State of Utah in 1987 as Gallup Acquisitions, Inc., and subsequently changed our name to First Preference Fund, Inc in 1992. We became a Texas corporation by a merger effected in July 1992, through which our name became GulfWest Oil Company. On May 21, 2001, we changed our name to GulfWest Energy Inc.

On June 29, 2005 we merged with and into Crimson Exploration Inc., a Delaware corporation (Crimson), for the purpose of changing our state of incorporation from Texas to Delaware (the Reincorporation). The Reincorporation was accomplished pursuant to an Agreement and Plan of Merger, dated June 28, 2005, which was approved by GulfWest s shareholders at the 2005 Annual Shareholders Meeting held June 1, 2005.

Our principal office is currently located at 480 North Sam Houston Parkway East, Suite 300, Houston, Texas 77060 and our telephone number is (281) 820-1919. However, we look forward to moving our offices to downtown Houston at the end of April 2007.

Prior to March 2, 2006 Crimson Exploration Inc. had six active and three inactive, direct or indirect, wholly owned subsidiaries. The active subsidiaries were:

1. **GulfWest Oil and Gas Company**, a Texas corporation, was organized February 18, 1999 and was the owner of record of interests in certain crude oil and natural gas properties located in Colorado and Texas. It had one wholly owned subsidiary, GulfWest Oil and Gas Company (Louisiana) LLC.
2. **GulfWest Oil and Gas Company (Louisiana) LLC**, a Louisiana company, was formed July 31, 2001 and was the owner of record of interests in certain crude oil and natural gas properties in Louisiana.
3. **SETEX Oil and Gas Company**, a Texas corporation, was organized August 11, 1998 and was the operator of crude oil and natural gas properties in which we own a majority working interest.
4. **RigWest Well Service, Inc.**, a Texas corporation, was organized September 5, 1996 and operates well servicing equipment for our own account and for others when not being utilized for our own account.
5. **DutchWest Oil Company**, a Texas corporation, was organized July 28, 1997 and was the owner of record of interests in certain crude oil and natural gas properties located along the Gulf Coast of Texas.
6. **GulfWest Development Company**, a Texas corporation, was organized November 9, 2000 and was the owner of record of interests in certain crude oil and natural gas properties located in Texas and Mississippi.

On January 5, 2006 we formed Crimson Exploration Operating, Inc., a Delaware corporation, as our wholly owned subsidiary through which all oil and gas operations will be conducted. Effective March 2, 2006 we merged all our subsidiaries referred to above into this newly formed corporation. LTW Pipeline Co. remains an inactive subsidiary of Crimson Exploration Inc.

Balance. At December 31, 2006, our proved reserves were comprised of 32% crude oil and 68% natural gas. We will continue to expand our role in the domestic natural energy industry by (i) acquiring additional interests in crude oil and natural gas properties, (ii) increasing the production and reserve base of our existing producing properties, and (iii) developing an internal prospect generation capability for exploratory prospects. Our goal is to have greater control of our natural gas transportation and marketing, and an expanded role in the transportation of natural gas produced by other parties in our area of operations. We are presently focusing our *workover* and development efforts on both crude oil and natural gas reserves to take advantage of the higher prices of both commodities.

In 2005, we recapitalized Crimson Exploration Inc. through the sale of preferred stock for $42.0 million. The net proceeds were used to repay all outstanding debt and other past due liabilities and for general corporate purposes. We also established a $100.0 million senior secured revolving credit facility with Wells Fargo Bank, N.A. In 2006, we also established a $150.0 million subordinate credit facility and effected a 1-for-10 reverse stock split. Details of this activity are described in Part II, Item 7 Financial Recapitalization .

Recent Developments

Effective August 31, 2006, we entered into a $150 million subordinate credit facility with Wells Fargo Energy Capital, Inc. (the Subordinate Credit Agreement). Initial availability under the Subordinate Credit Agreement is $15.0 million. No borrowings under the Subordinate Credit Agreement were made at closing, nor were any outstanding at December 31, 2006.

The facility will be secured on a subordinated basis by a lien on all the assets of the Company and its subsidiaries, as well as a security interest in the stock of all the Company s subsidiaries. The obligations under the Subordinate Credit Agreement will be subordinate and junior to those under our $100.0 million senior secured revolving credit facility with Wells Fargo Bank, National Association (the Senior Credit Agreement).

The Subordinate Credit Agreement has a term of three-and-a-half years, and all principal amounts, together with all accrued and unpaid interest, will be due and payable in full on February 28, 2010. Proceeds from extensions of credit under the facility will be for acquisitions of oil and gas properties and for general corporate purposes.

Advances under the Subordinate Credit Agreement will be in the form of either base rate loans or Eurodollar loans. The interest rate on the base rate loans fluctuates based upon the higher of (1) the lender s prime rate and (2) the Federal Funds rate, plus a margin of 0.50%, plus an additional margin of 3.75%. The interest rate on the Eurodollar loans fluctuates based upon the rate at which Eurodollar deposits in the London Interbank market (Libor) are quoted for the maturity selected, plus a margin of 5.25%. Eurodollar loans of one, three and six months may be selected by the Company. A commitment fee of 0.50% on the unused portion of the borrowing base will accrue, and be payable quarterly in arrears. Repayments made during the first twelve months of the term Subordinate Credit Agreement will be subject to a 1% prepayment penalty. Once repaid, amounts under the Subordinate Credit Agreement may not be re-borrowed.

Under the Subordinate Credit Agreement, borrowings are at our discretion. However, once the Company s outstanding balance under the Senior Credit Agreement reaches $10.0 million, the Company s next $10.0 million in borrowings must be funded under the Subordinate Credit Agreement.

The credit agreements include usual and customary affirmative covenants for credit facilities of this type and size, as well as customary negative covenants, including, among others, limitation on liens, hedging, mergers, asset sales or dispositions, payments of dividends, incurrence of additional indebtedness, certain leases and investments outside of the ordinary course of business. At December 31, 2006 we were in compliance with the aforementioned covenants.

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On September 15, 2006, we effected a reverse stock split where each ten shares of outstanding common stock were exchanged for one new share of common stock. All periods presented have been adjusted to reflect the effects of the reverse stock split.

On March 24, 2006 we issued 323,565 shares of common stock, valued at approximately $2.4 million, as partial consideration for the acquisition of oil and gas leases via merger with Core Natural Resources, Inc. As a result of this transaction we also increased the book value of oil and gas leases by recording a $1.6 million deferred tax liability related to the difference in the fair market value of the assets acquired and their underlying tax basis. Related to this transaction, we also acquired a 2% overriding royalty interest in that leasehold acreage by issuing 46,224 shares of common stock valued at $0.3 million.

Our Business Strategy

We have pursued a business strategy of acquiring interests in crude oil and natural gas *producing properties* where production and reserves can be increased through exploitation activities. Such activities include *workovers*, development drilling, *recompletions*, replacement or addition of equipment and *waterflood* or other secondary recovery techniques. Key elements of our business strategy include:

Development and Exploitation of Existing Properties. Our strategy is to increase crude oil and natural gas production and reserves of our existing assets through relatively low-risk development activities, such as performing *workovers*, *recompletions* and *horizontal drilling* from existing well bores, infield drilling and more efficiently using production facilities.

Acquisition Program. Since we were capital constrained during 2002 through February 2005, we made no acquisitions during that period. To the extent financial resources are available, we intend to continue to pursue the acquisition of interests in producing crude oil and natural gas properties (i) held by small, under-capitalized operators and (ii) being divested by larger independent and major oil and gas companies, or through corporate transactions.

Significant Operating Control. Currently, we are the operator of all but three of the wells in which we own working interests. This operating control enables us to better manage the nature, timing and costs of developing and servicing such wells, and the timing and marketing of the resulting production.

Ownership of Workover Rigs. We currently own two workover service rigs that we operate for our own account. By owning and operating this equipment, we are better able to control costs, quality of operations and availability of equipment and services.

Expanded Exploration and Exploitation Role. Historically, we have not drilled exploratory wells due to the cost and risk associated with drilling prospective locations. However, since the end of 1998, we have acquired *producing properties* that have included significant acreage for prospective oil and gas exploration. These include producing wells and acreage in Grimes, Hardin, Jim Wells, Madison, Palo Pinto, Refugio, Victoria, Wharton and Zavala, Counties, Texas; Adams, Arapaho, Elbert and Weld Counties, Colorado; Cameron Parish, Louisiana; and Jones County, Mississippi. These acquisitions have added existing natural gas and crude oil production to our asset base and, as importantly, have provided us with immediate geological databases for development drilling opportunities as well as the potential for generating exploratory opportunities on the acquired acreage. We have expanded our evaluation efforts in these fields and intend to increase our development of reserves through workovers of existing wells and by drilling additional wells. As we develop exploration opportunities on these properties or see high-quality prospects generated by others, as capital resources are available, we will complement our development activities with capital for exploratory or exploitation projects.

We are also actively pursuing the development of an internal prospect generation capability to identify higher potential drilling opportunities and have entered into an exploration agreement with a prospect generator under which we get a right of first refusal on prospects they generate.

Our Employees

At March 19, 2007, we had 33 full time employees, of whom 14 were field personnel. None of our employees are covered by collective bargaining agreements.

Government Regulation

Federal and State Regulatory Requirements

We are a public company subject to the rules and regulations of the SEC. Recently enacted and proposed changes in the laws and regulations affecting public companies, including the provisions of the Sarbanes-Oxley Act of 2002 and rules adopted by the SEC, have resulted in increased costs to us. The new rules could make it more difficult for us to obtain certain types of insurance, including director and officer liability insurance, and we may be forced to accept reduced policy limits and coverage or incur substantially higher costs to obtain the same or similar coverage. The impact of these events could also make it more difficult for us to attract and retain qualified persons to serve on our board of directors, our board committees or as executive officers.

Our operations are subject to numerous laws and regulations governing the operation and maintenance of our facilities and the discharge of materials into the environment or otherwise relating to environmental protection. These laws and regulations may require that we acquire permits before commencing drilling; restrict the substances that can be released into the environment in connection with drilling and production activities; limit or prohibit drilling activities on protected areas such as wetlands or wilderness areas; or require remedial measures to mitigate pollution from former operations. Under these laws and regulations, we could be liable for personal injury and clean-up costs and other environmental and property damages, as well as administrative, civil and criminal penalties. These laws and regulations have been changed frequently in the past. In general, these changes have imposed more stringent requirements that increase operating costs or require capital expenditures in order to remain in compliance. It is also possible that unanticipated developments could cause us to make environmental expenditures that are significantly different from those we currently expect. Existing laws and regulations could be changed, and any changes could have an adverse effect on our business.

Environmental Regulations

The oil and gas business is subject to environmental hazards, such as oil spills, gas leaks and ruptures and discharges of petroleum products and hazardous substances, and historic disposal activities. These environmental hazards could expose us to material liabilities for property damages, personal injuries or other environmental harm, including costs of investigating and remediating contaminated properties. In addition, we also may be liable for environmental damages caused by the previous owners or operators of properties that we have purchased or are currently operating. A variety of stringent federal, state and local laws and regulations govern the environmental aspects of our business and impose strict requirements for, among other things, well drilling or workover, operation and abandonment, waste management; land reclamation; and controlling air, water and waste emissions.

Any noncompliance with these laws and regulations could subject us to material administrative, civil or criminal penalties or other liabilities. Additionally, our compliance with these laws may, from time to time, result in increased costs to our operations or decreased production, and may affect our costs of acquisitions. Environmental laws may, in the future, cause a decrease in our production or an increase in the costs of production, development or exploration. Pollution and similar environmental risks generally are not fully insurable.

We have not incurred any material costs relating to our compliance with federal, state or local laws during the year ended December 31, 2006, or during the subsequent interim period.

Title to Properties

Our properties are subject to customary royalty interests, liens incident to operating agreements, liens for current taxes and other burdens, including other mineral encumbrances and restrictions. We do not believe that any of these burdens materially interfere with our use of the properties in the operation of our business.

We believe that we have generally satisfactory title to or rights in all of our producing properties. As is customary in the oil and gas industry, we make minimal investigation of title at the time we acquire undeveloped properties. We make title investigations and receive title opinions of local counsel only before we commence drilling operations. We believe that we have satisfactory title to all of our other assets. Although title to our properties is subject to encumbrances in certain cases, we believe that none of these burdens will materially detract from the value of our properties or from our interest therein or will materially interfere with our use in the operation of our business.

Competition

The oil and gas industry is highly competitive and we compete with a substantial number of other companies that have greater resources. Many of these companies explore for, produce and market oil and gas, 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 gas properties, and obtaining purchasers and transporters of the oil and gas we produce. There is also competition between producers of oil and gas and other industries producing alternative 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; however, it is not possible to predict the nature of any such legislation or regulation that may ultimately be adopted or its effects upon our future operations. Such laws and regulations may, however, substantially increase the costs of exploring for, developing or producing gas and oil and may prevent or delay the commencement or continuation of a given operation. The effect of these risks cannot be accurately predicted.

Insurance Matters

As is common in the oil and gas industry, we will not insure fully against all risks associated with our business either because such insurance is not available or because premium costs are considered prohibitive. A loss not fully covered by insurance could have a materially adverse effect on our financial position, results of operations or cash flows.

Executive Officers

See Item 10 of this report, which information is incorporated herein by reference.

ITEM 1A. Risk Factors

Our success depends heavily upon our ability to market our crude oil and natural gas production at favorable prices.

In recent decades there have been both periods of worldwide overproduction and underproduction of crude oil and natural gas and periods of increased and relaxed energy conservation efforts. Such conditions have resulted in excess supply of, and reduced demand for, crude oil on a worldwide basis and for natural gas on a domestic basis. At other times, there has been short supply of, and increased demand for, crude oil and, to a lesser extent, natural gas. These changes have resulted in dramatic price fluctuations.

We may borrow funds to finance capital expenditures and for other purposes which could possibly have important consequences to our shareholders, including the following:

- (i) Our indebtedness, acquisitions, working capital, capital expenditures or other purposes may be impaired;
- (ii) Funds available for our operations and general corporate purposes or for capital expenditures will be reduced as a result of the dedication of a portion of our consolidated cash flow from operations to the payment of the principal and interest on our indebtedness;
- (iii) We may be more highly leveraged than certain of our competitors, which may place us at a competitive disadvantage;

(iv) The agreements governing our long-term indebtedness and bank loans may contain restrictive financial and operating covenants;
(v) An event of default (not cured or waived) under financial and operating covenants contained in our debt instruments could occur and have a material adverse effect;
(vi) Certain of the borrowings under our debt agreements could have floating rates of interest, which would cause us to be vulnerable to increases in interest rates; and
(vii) Our degree of leverage could make us more vulnerable to a downturn in general economic conditions.
(viii) Our revolving credit facility and subordinate credit agreement contain a number of significant negative covenants that place limits on our activities and operations, including those relating to:

- creation of liens,
- hedging,
- mergers, acquisitions, asset sales or dispositions,
- payments of dividends,
- incurrence of additional indebtedness, and
- certain leases and investments outside of the ordinary course of business.

In addition, our revolving credit facility and subordinate credit agreement require us to maintain compliance with specified financial ratios and satisfy certain financial condition tests. Our ability to comply with these ratios and financial condition tests may be affected by events beyond our control, and we cannot assure you that we will meet these ratios and financial condition tests. These financial ratio restrictions and financial condition tests could limit our ability to obtain future financings, make needed capital expenditures, withstand a future downturn in our business or the economy in general or otherwise conduct necessary or desirable corporate activities.

A breach of any of these covenants or our inability to comply with the required financial ratios or financial condition tests could result in a default under our credit facilities. A default, if not cured or waived, could result in all of our indebtedness becoming immediately due and payable. If that should occur, we may not be able to pay all such debt or to borrow sufficient funds to refinance it. Even if new financing were then available, it may not be on terms that are acceptable to us.

We have outstanding debt of $8.5 million on our revolving credit facility and shareholders equity of $60.2 million at December 31, 2006. We may borrow up to an additional $16.5 million under our revolving credit facility and $15.0 million under our subordinate credit facility to fund acquisitions or for general corporate purposes. Our debt obligations could increase substantially.

We have incurred net losses in the past and there can be no assurance that we will be profitable in the future.

We have incurred net losses in four of the last five fiscal years. We cannot assure you that our current level of operating results will continue or improve. Our activities could require additional debt or equity financing on our part. Since the terms and availability of this financing depend to a large degree upon general economic conditions and third parties over which we have no control, we can give no assurance that we will obtain the needed financing or that we will obtain such financing on attractive terms. In addition, our ability to obtain financing depends on a number of other factors, many of which are also beyond our control, such as interest rates and national and local business conditions. If the cost of obtaining needed financing is too high or the terms of such financing are otherwise unacceptable in relation to the opportunity we are presented with, we may decide to forego that opportunity. Additional indebtedness could increase our leverage and make us more vulnerable to economic downturns and may limit our ability to withstand competitive pressures. Additional equity financing could result in dilution to our shareholders. Our future operating results may fluctuate significantly depending upon a number of factors, including industry conditions, prices of crude oil and natural gas, rates of production, timing of capital expenditures and drilling success. These variables could have a material adverse effect on our business, financial condition, results of operations and the market price of our Common Stock.

Estimates of crude oil and natural gas reserves depend on many assumptions that may turn out to be inaccurate.

Estimates of our *proved reserves* for crude oil and natural gas and the estimated future net revenues from the production of such reserves rely upon various assumptions, including assumptions as to crude oil and natural gas prices, drilling and operating expenses, capital expenditures, taxes and availability of funds. The process of estimating crude oil and natural gas reserves is complex and imprecise. Actual future production, crude oil and natural gas prices, revenues, taxes, development expenditures, operating expenses and quantities of recoverable crude oil and natural gas reserves may vary substantially from the estimates we obtain from reserve engineers. Any significant variance in these assumptions could materially affect the estimated quantities and *present value* of reserves we have set forth. In addition, our *proved reserves* may be subject to downward revision due to factors that are beyond our control, such as production history, results of future exploration and development, prevailing crude oil and natural gas prices and other factors.

Approximately 12% of our total estimated *proved reserves* at December 31, 2006 were *proved undeveloped reserves*, which are by their nature less certain.

Recovery of such reserves requires significant capital expenditures and successful drilling operations. The reserve data set forth in the reserve engineer reports assumes that substantial capital expenditures are required to develop such reserves. Although cost and reserve estimates attributable to our crude oil and natural gas reserves have been prepared in accordance with industry standards, we cannot be sure that the estimated costs are accurate, that development will occur as scheduled or that the results of such development will be as estimated.

You should not interpret the *present value* referred to in this annual report as the current market value of our estimated crude oil and natural gas reserves.

In accordance with Securities and Exchange Commission requirements, the estimated discounted future net cash flows from *proved reserves* are generally based on prices and costs as of the date of the estimate. Actual future prices and costs may be materially higher or lower.

The estimates of our *proved reserves* and the future net revenues from which the *present value* of our properties is derived were calculated based on the actual prices of our various properties on a property-by-property basis at December 31, 2006. The average sales prices of all properties were $57.67 per barrel of oil and $5.40 per thousand cubic feet (*Mcf*) of natural gas at that date.

Actual future net cash flows will also be affected by increases or decreases in consumption by crude oil and natural gas purchasers and changes in governmental regulations or taxation. The timing of both the production and the incurring of expenses in connection with the development and production of crude oil and natural gas properties affect the timing of actual future net cash flows from *proved reserves*. In addition, the 10% discount factor, which is required by the Securities and Exchange Commission to be used in calculating discounted future net cash flows for reporting purposes, is not necessarily the most appropriate discount factor. The effective interest rate at various times and the risks associated with our business or the oil and gas industry in general will affect the accuracy of the 10% discount factor.

Except to the extent that we acquire properties containing *proved reserves* or conduct successful development or exploitation activities, our *proved reserves* will decline as they are produced.

In general, the volume of production from crude oil and natural gas properties declines as reserves are depleted. Our future crude oil and natural gas production is highly dependent upon our success in finding or acquiring additional reserves.

The business of acquiring, enhancing or developing reserves requires considerable capital.

Our ability to make the necessary capital investment to maintain or expand our asset base of crude oil and natural gas reserves could be impaired to the extent that cash flow from operations is reduced and external sources of capital become limited or unavailable. In addition, we cannot be sure that our future acquisition and development activities will result in additional *proved reserves* or that we will be able to drill productive wells at acceptable costs.

Crude oil and natural gas drilling and production activities are subject to numerous risks, many of which are beyond our control. These risks include (i) the possibility that no commercially productive oil or gas reservoirs will be encountered; and, (ii) that operations may be curtailed, delayed or canceled due to title problems, weather conditions, governmental requirements, mechanical difficulties, or delays in the delivery of drilling rigs and other equipment that may limit our ability to develop, produce and market our reserves. We cannot assure you that new wells we drill will be productive or that we will recover all or any portion of our investment in such new wells.

Drilling for crude oil and natural gas may not be profitable.

Any wells that we drill may be dry wells or wells that are not sufficiently productive to be profitable after drilling. Such wells will have a negative impact on our profitability. In addition, our properties may be susceptible to drainage from production by other operators on adjacent properties.

The interpretation and analysis of 3-D seismic data does not allow the interpreter to know if hydrocarbons are present or economically producible.

Our decisions to purchase, explore, develop and exploit prospects or properties depend in part on data obtained through geophysical and geological analyses, production data and engineering studies, the results of which are uncertain. Even when used and properly interpreted, 3-D seismic data and visualization techniques only assist geoscientists and geologists in identifying subsurface structures and hydrocarbon indicators. They do not allow the interpreter to know if hydrocarbons are present or producible economically. In addition, the use of 3-D seismic and other advanced technologies require greater predrilling expenditures than traditional drilling strategies.

Our industry experiences numerous operating risks that could cause us to suffer substantial losses.

Such risks include fire, hurricanes, explosions, blowouts, pipe failure and environmental hazards, such as oil spills, natural gas leaks, ruptures or discharges of toxic gases. We could also suffer losses due to personnel injury or loss of life; severe damage to or destruction of property; or environmental damage that could result in clean-up responsibilities, regulatory investigation, penalties or suspension of our operations. In accordance with customary industry practice, we maintain insurance policies against some, but not all, of the risks described above. Our insurance policies may not adequately protect us against loss or liability. There is no guarantee that insurance policies that protect us against the many risks we face will continue to be available at justifiable premium levels.

As owners and operators of crude oil and natural gas properties, we may be liable under federal, state and local environmental regulations for activities involving water pollution, hazardous waste transport, storage, disposal or other activities.

Our past growth has been attributable to acquisitions of producing crude oil and natural gas properties with *proved reserves*. There are risks involved with such acquisitions.

The successful acquisition of properties requires an assessment of recoverable reserves, future crude oil and natural gas prices, operating costs, potential environmental and other liabilities, and other factors beyond our control. Such assessments are necessarily inexact and their accuracy uncertain. In connection with such an assessment, we perform a review of the subject properties that we believe to be generally consistent with industry practices. Such a review, however, will not reveal all existing or potential problems, nor will it permit us, as the buyer, to become sufficiently familiar with the properties to fully assess their capabilities or deficiencies. We may not inspect every well and, even when an inspection is undertaken, structural and environmental problems may not necessarily be observable.

When we acquire properties, in most cases, we are not entitled to contractual indemnification for pre-closing liabilities, including environmental liabilities.

We generally acquire interests in properties on an as is basis with limited remedies for breaches of representations and warranties, and in these situations we cannot assure you that we will identify all areas of existing or potential exposure. In those circumstances in which we have contractual indemnification rights for pre-closing liabilities, we cannot assure you that the seller will be able to fulfill its contractual obligations. In addition, the competition to acquire producing crude oil and natural gas properties is intense and many of our larger competitors have financial and other resources substantially greater than ours. We cannot assure you that we will be able to acquire producing crude oil and natural gas properties that have economically recoverable reserves for acceptable prices.

We may acquire *royalty, overriding royalty* or *working interests* in properties that are less than the controlling interest.

In such cases, it is likely that we will not operate, nor control the decisions affecting the operations, of such properties. We intend to limit such acquisitions to properties operated by competent parties with whom we have discussed their plans for operation of the properties.

We will need additional financing in the future to continue to fund our development and exploitation activities.

We have made and will continue to make substantial capital expenditures in our exploitation and development projects. We intend to finance these capital expenditures with cash flow from operations, existing financing arrangements or new financing. We cannot assure you that such additional financing will be available. If it is not available, our development and exploitation activities may have to be curtailed, which could adversely affect our business, financial condition and results of operations.

The marketing of our natural gas production depends, in part, upon the availability, proximity and capacity of natural gas gathering systems, pipelines and processing facilities.

We could be adversely affected by changes in existing arrangements with transporters of our natural gas since we do not own most of the gathering systems and pipelines through which our natural gas is delivered to purchasers. Our ability to produce and market our natural gas could also be adversely affected by federal, state and local regulation of production and transportation.

The crude oil and natural gas industry is highly competitive in all of its phases.

Competition is particularly intense with respect to the acquisition of desirable *producing properties*, the acquisition of crude oil and natural gas prospects suitable for enhanced production efforts, the obtaining of goods and services from industry providers, and the hiring of experienced personnel. Our competitors in crude oil and natural gas acquisition, development, and production include the major oil companies, in addition to numerous independent crude oil and natural gas companies, individual proprietors and drilling programs.

Many of these competitors possess and employ financial and personnel resources substantially in excess of those which are available to us and may, therefore, be able to pay more for desirable *producing properties* and *prospects* and to define, evaluate, bid for, and purchase a greater number of *producing properties* and *prospects* than our financial or personnel resources will permit. Our ability to generate reserves in the future will be dependent on our ability to select and acquire suitable *producing properties* and *prospects* while competing with these companies.

The domestic oil industry is extensively regulated at both the federal and state levels. Although we believe we are presently in compliance with all laws, rules and regulations, we cannot assure you that changes in such laws, rules or regulations, or the interpretation thereof, will not have a material adverse effect on our financial condition or the results of our operations.

Legislation affecting the oil and gas industry is under constant review for amendment or expansion, frequently increasing the regulatory burden on the industry. There are numerous federal and state agencies authorized to issue rules and regulations affecting the oil and gas industry. These rules and regulations are often difficult and costly to comply with and carry substantial penalties for noncompliance.

State statutes and regulations require permits for drilling operations, drilling bonds, and reports concerning operations. Most states also have statutes and regulations governing conservation matters, including the unitization or pooling of properties, and the establishment of maximum rates of production from wells. Some states have also enacted statutes prescribing price ceilings for natural gas sold within their states.

Our industry is also subject to numerous laws and regulations governing plugging and abandonment of wells, discharge of materials into the environment and other matters relating to environmental protection. The heavy regulatory burden on the oil and gas industry increases the costs of our doing business as an oil and gas company, consequently affecting our profitability.

We have blank check preferred stock.

Our Certificate of Incorporation authorizes the Board of Directors to issue preferred stock without further shareholder action in one or more series and to designate the dividend rate, voting rights and other rights preferences and restrictions. The issuance of preferred stock could have an adverse impact on holders of Common Stock. Preferred stock is senior to Common Stock. Additionally, preferred stock could be issued with dividend rights senior to the rights of holders of Common Stock. Finally, preferred stock could be issued as part of a poison pill , which could have the effect of deterring offers to acquire the Company. See Description of Securities

We are not paying dividends on our Common Stock.

Our board of directors presently intends to retain all of our earnings for the expansion of our business; therefore we do not anticipate distributing cash dividends on our Common Stock in the foreseeable future. Any decision of our board of directors to pay cash dividends will depend upon our earnings, financial position, cash requirements and other factors.

One investor controls us.

As a result of preferred stock offerings in February 2005, OCMGW Holdings (OCMGW) acquired a controlling interest in us. OCMGW has or has the right to acquire approximately 5.2 million shares of our Common Stock pursuant to conversion of Series G Preferred Stock, including undeclared convertible dividends, and Series H Preferred Stock owned by it which represents approximately 54% of the currently outstanding Common Stock, assuming the conversion of preferred stock and undeclared dividends held by it. Pursuant to the terms of Series G Preferred Stock, the holders of the Series G Preferred Stock, voting as a class, have the right to elect a majority of our board of directors. OCMGW currently owns approximately 95% of the Series G Preferred Stock.

Additionally, OCMGW and all current directors and officers as a group represent approximately 55% of the outstanding voting power (assuming they convert all preferred stock other than the Series G Preferred Stock and Series H Preferred Stock, which vote on an as converted basis, and exercise all currently exercisable warrants and options held by them). For as long as OCMGW and the other directors and officers continue to own over a majority of the outstanding voting power, they will be able to control matters submitted to shareholders. The percentage ownership of OCMGW, directors and officers could be reduced by the issuance of Common Stock on conversion of preferred stock and the exercise of warrants, although it is impossible to say how many shares will be actually issued.

The holders of our Common Stock do not have cumulative voting rights, preemptive rights or rights to convert their Common Stock to other securities.

We are authorized to issue 200.0 million shares of Common Stock, $0.001 par value per share. As of March 19, 2007 there were 3.3 million shares of Common Stock issued and outstanding. Since the holders of our Common Stock do not have cumulative voting rights, the holder(s) of a majority of the shares of Common Stock, and Series G Preferred Stock and Series H Preferred Stock (on an as converted basis) present, in person or by proxy, will be able to elect all of the remaining members of our board of directors that the holders of the Series G Preferred Stock are not entitled to elect as a class. The holders of shares of our Common Stock do not have preemptive rights or rights to convert their Common Stock into other securities.

The number of shares of outstanding Common Stock could increase significantly as a result of the 2005 sale of Series G Preferred Stock sold to OCMGW and Affiliates.

If all of the Common Stock underlying our various convertible and derivative securities, including warrants and granted employee stock options, is issued by us, the number of our outstanding shares of Common Stock would increase to approximately 8.7 million shares. Currently, we are only authorized to issue 200.0 million shares of our Common Stock, 3.3 million shares of which are outstanding as of March 19, 2007. It is impossible to say how many shares, if any, we will issue and how many shares, in turn, will be resold. However, it is possible that our stock price could decline significantly as a result of an increased number of shares being offered into the market.

Our 1-for-10 reverse stock split could cause a reduction in the total market value of our common stock, increase the volatility of our stock price and has increased the number of shares of common stock we may issue.

Our 1-for-10 reverse stock split effectuated after the close of business on September 15, 2006, where each 10 shares of our common stock was combined and converted into one share of common stock, with any fractional shares resulting from the split rounded upward to the nearest whole number of shares, could reduce the liquidity of our common stock. Reduced liquidity may reduce the value of our common stock and our ability to use our equity as consideration for an acquisition or other corporate opportunity. In addition, the reverse split has decreased the number of shares outstanding, giving individual orders the potential to create increased volatility in our stock price. As a result of the reverse stock split, we are able to issue significantly more shares of our common stock which could have a material adverse affect on the market price of our common stock. We are currently authorized to issue 200.0 million shares of common stock and, as a result of the reverse stock split, have approximately 3.3 million shares outstanding based on our capitalization as of March 19, 2007.

ITEM 2. Properties

At December 31, 2006, we owned a total of 245 *gross wells*, of which 119 were *producing*, 105 were shut-in or temporarily abandoned and 21 were injection or saltwater wells. We owned an average 86% *working interest* in the 119 gr*oss* (103 *net*) *producing wells*. Gross *wells* are the total wells in which we own a *working interest*. *Net wells* are the sum of the fractional *working interests* we own in *gross wells*. Our part of the estimated *proved reserves* these properties contain was approximately 2.5 million barrels (*MMBL*) of oil and 31.4 billion cubic feet (*Bcf*) of natural gas at December 31, 2006. Substantially all of our properties are located onshore in Texas, Colorado, Mississippi and Louisiana or shallow inland waters in Louisiana.

Proved Reserves

The following table reflects our estimated *proved reserves* at December 31 for each of the preceding three years.

	2006	**2005**	**2004**
Crude Oil (*MBbl*)			
Developed	2,250	2,423	2,575
Undeveloped	251	285	388
Total	2,501	2,708	2,963
Natural Gas (*MMcf*)			
Developed	27,146	19,658	20,966
Undeveloped	4,242	4,992	8,125
Total	31,388	24,650	29,091
Total (*MMcfe*)	46,394	40,898	46,869

(a) Approximately 88% of our total *proved reserves* was classified as proved developed at December 31, 2006.

Standardized Measure of Discounted Future Net Cash Flows

The following table sets forth as of December 31 for each of the preceding three years, the estimated future net cash flow from and *standardized measure* of discounted future net cash flows of our *proved reserves*, which were prepared in accordance with the rules and regulations of the SEC and the Financial Accounting Standard Board. Future net cash flow represents future gross cash flow from the production and sale of *proved reserves*, net of crude oil and natural gas production costs (including production taxes, ad valorem taxes and operating expenses) and future development costs. The calculations used to produce the figures in this table are based on current cost and price factors at December 31 for each year. We cannot assure you that the *proved reserves* will all be developed within the periods used in the calculations or those prices and costs will remain constant.

	2006	**2005**	**2004**
Future cash inflows	$ 313,312,927	$ 425,080,357	$ 290,998,312
Future production and development costs:			
Production	108,693,762	101,677,305	80,880,330
Development	26,229,488	27,467,896	24,141,982
Future cash flows before income taxes	178,389,677	295,935,156	185,976,000
Future income taxes	(43,534,046)	(91,664,228)	(49,871,272)
Future net cash flows after income taxes	134,855,631	204,270,928	136,104,728
10% annual discount for estimated timing of cash flows	(57,442,604)	(85,873,789)	(52,602,351)
Standardized measure of discounted future net cash flows	$ 77,413,027	$ 118,397,139	$ 83,502,377

(1) The average sales prices utilized in the estimation of our proved reserves were $57.67 per Bbl and $5.40 per Mcf, $57.79 per Bbl and $10.90 per Mcf and $40.41 per Bbl and $5.89 per Mcf, at December 31, 2006, 2005 and 2004, respectively.

Significant Properties

Summary information on our properties with *proved reserves* is set forth below as of December 31, 2006.

	Productive Wells		Proved Reserves			Present Value[(1)]
	Gross Productive Wells	Net Productive Wells	Crude Oil (*MBbl*)	Natural Gas (*MMcf*)	Total (*MMcfe*)	Amount ($M)
Texas	66	61.64	968	19,329	25,137	$46,242
Colorado	35	24.44	323	5,879	7,817	18,492
Louisiana	16	16.00	1,163	6,180	13,156	36,964
Mississippi	1	0.37	47		284	704
Offshore	1	0.25				
Total	119	102.70	2,501	31,388	46,394	$102,402

(1) The average sales prices used in the estimation of our proved reserves were $57.67 per Bbl and $5.40 per Mcf at December 31, 2006.

All information set forth herein relating to our proved reserves, estimated future net cash flows and present values is taken from reports prepared by independent petroleum engineers. The estimates of these engineers were based upon their review of production histories and other geological, economic, ownership and engineering data

provided by and relating to us. No reports on our reserves have been filed with any federal agency. In accordance with the SEC s guidelines, our estimates of proved reserves and the future net revenues from which present values are derived are made using year end crude oil and natural gas sales prices held constant throughout the life of the properties (except to the extent a contract specifically provides otherwise). Operating costs, development costs and certain production-related taxes were deducted in arriving at estimated future net revenues, but such costs do not include debt service, general and administrative expenses and income taxes.

There are numerous uncertainties inherent in estimating crude oil and natural gas reserves and their values, including many factors beyond our control. The reserve data set forth in this report are based upon estimates. Reservoir engineering is a subjective process, which involves estimating the sizes of underground accumulations of crude 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, engineering and geological interpretation of that data and judgment. As a result, estimates of different engineers, including those used by us, may vary. In addition, estimates of reserves are subject to revision based upon actual production, results of future development, exploitation and exploration activities, prevailing crude oil and natural gas prices, operating costs and other factors. Such revisions may be material. Accordingly, reserve estimates are often different from the quantities of crude oil and natural gas that are ultimately recovered and are highly dependent upon the accuracy of the assumptions upon which they are based. We cannot assure you that the estimates contained in this report are accurate predictions of our crude oil and natural gas reserves or their values. Estimates with respect to proved reserves that may be developed and produced in the future are often based upon volumetric calculations and upon analogy to similar types of reserves rather than upon actual production history. Estimates based on these methods are generally less reliable than those based on actual production history. Subsequent evaluation of the same reserves based upon production history will result in potentially substantial variations in the estimated reserves.

Production, Revenue and Price History

The following table sets forth information (associated with our proved reserves) regarding production volumes of crude oil and natural gas, revenues and expenses attributable to such production (all net to our interests) and certain price and cost information as of December 31 for each of the preceding three years.

	2006	**2005**	**2004**
Production			
Oil (*Bbl*)	184,881	177,833	173,865
Natural gas (*Mcf*)	1,542,423	1,482,250	1,033,433
Total (*MCFE*)	2,651,709	2,549,248	2,076,623
Revenue			
Oil production	$ 10,908,030	$ 7,044,429	$ 5,498,598
Natural gas production	10,569,705	10,507,221	5,602,516
Total	$ 21,477,735	$ 17,551,650	$ 11,101,114
Operating Expenses	$ 7,527,589	$ 5,585,297	$ 4,879,754
Production Data			
Average sales price (1)			
Per barrel of oil	$ 59.00	$ 39.61	$ 31.63
Per *Mcf* of natural gas	$ 6.85	$ 7.09	$ 5.42
Per *MCFE*	$ 8.10	$ 6.89	$ 5.35
Average expenses per *MCFE*			
Lease operating	$ 2.84	$ 2.19	$ 2.35
Exploration expenses	$ 0.17	$ 0.16	$
Depreciation, depletion and Amortization	$ 1.49	$ 1.23	$ 1.05
General and administrative(2)	$ 3.29	$ 1.48	$ 0.92

(1) Average sales prices are shown net of the settled amounts of our oil and gas hedge contracts. Average sales prices per MCFE, before adjustments for the hedge contracts, were $8.34, $8.43 and $6.23 in 2006, 2005 and 2004, respectively.
(2) Non-cash stock option expense related to our adoption of SFAS 123R on January 1, 2006 was $1.39 per mcfe.

Productive Wells

The following table shows the number of producing wells we own by location at December 31, 2006:

	Gross Oil Wells	Net Oil Wells	Gross Gas Wells	Net Gas Wells
Texas	20	19.48	46	42.16
Colorado	18	11.89	17	12.55
Louisiana	12	12.00	4	4.00
Mississippi	1	0.37		
Offshore			1	0.25
Total	51	43.74	68	58.96

In addition, we have 105 inactive wells (101 net) and 21 salt water disposal wells (21 net).

Developed Acreage

The following table shows the developed acreage that we own, by location, at December 31, 2006 which is acreage spaced or assigned to productive wells. *Gross acres* are the total acres in which we own a working interest. Net acres are the sum of the fractional *working interests* we own in gross acres.

	Gross Acres	Net Acres
Texas	10,172	9,359
Colorado	3,000	2,100
Louisiana	1,440	1,440
Total	14,612	12,899

Undeveloped Acreage

The following table shows the undeveloped acreage that we own, by location at December 31, 2006. Undeveloped acreage is acreage on which wells have not been drilled or completed to a point that would form the basis to determine whether the property is capable of production of commercial quantities of crude oil and natural gas.

	Gross Acres	Net Acres
Texas	31,791	30,456
Colorado	14,300	10,700
Louisiana	160	160
Total	46,251	41,316

Drilling Results

During 2006, we drilled the Johnston Gas Unit #2 well and the Fuhlberg Gas Unit #1 well in the Madisonville (Rodessa) Field, Madison County, Texas. These wells contain high levels of hydrogen sulfide and other inert components and must be treated before being merchantable. The wells were completed and we are awaiting the completion of natural gas treating facilities and a salt water disposal well before bringing them online. Actual production levels will not be determined until the wells commence actual production.

Also, in 2006, we drilled two wells in the DJ Basin in Colorado. The wells are the Kissler #2 well located in Weld County, Colorado and the Amoco State Lease #41-16 well located in Adams County, Colorado. Both wells were successfully completed and are producing oil and natural gas.

In 2005, we drilled the Upchurch McDougald Gas Unit #1 well in the Iola Field, Grimes County, Texas. This well was completed as a natural gas well. Also in 2005, we participated as a working interest owner, but not as well operator, in the LyLidia #1 well, Jim Webb County, Texas and the Mustang Island Block 749 Gas Unit No. 2 exploratory well that was drilled in Texas state waters. Neither well was commercially productive.

During 2004, we drilled the Hassler Gas Unit #1 well in the Iola Field, Grimes County, Texas which was completed as a natural gas well.

Costs Incurred

The following table shows the costs incurred in our oil and gas producing activities for the past three years:

	2006	2005	2004
Property Acquisitions:			
Proved	$	$ 142,867	$ 6,742
Unproved	8,745,363	1,244,975	17,347

Development Costs	6,465,719	6,171,241	6,117,899
Exploration Costs	10,783,663	3,157,841	
Total	$ 25,994,745	$ 10,716,924	$ 6,141,988

Property Dispositions

The following table shows oil and gas property dispositions:

	2006	2005	2004
Oil and gas properties	$	$ 31,337	$ 5,425,040
Accumulated DD&A			(1,659,001)
Oil and gas properties, net	$	$ 31,337	$ 3,766,039

As a result of these sales, we recorded a loss on sale of $13,022 and $2.0 million in 2005 and 2004 respectively.

Marketing

We sell substantially all of our crude oil and natural gas production to purchasers pursuant to sales contracts that typically have a thirty-day primary term, although occasionally we enter into longer term contracts when it is advantageous to do so. The sales prices for crude oil and condensate are tied to industry standard posted prices plus negotiated premiums. The sales prices for natural gas are based upon published index prices, subject to negotiated price deductions.

ITEM 3. Legal Proceedings

From time to time, we are involved in litigation relating to claims arising out of our operations or from disputes with vendors in the normal course of business. As of March 19, 2007, we were not engaged in any legal proceedings that are expected, individually or in the aggregate, to have a material adverse effect on the Company.

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

We did not submit any matters to a vote of our security holders during the fourth quarter of the fiscal year ended December 31, 2006.

PART II

ITEM 5. Market for Registrant s Common Equity and Related Stockholder Matters

The high and low trading prices for the Common Stock for each quarter in 2006 and 2005 are set forth below. The trading prices represent prices between dealers, without retail mark-ups, mark-downs, or commissions, and may not necessarily represent actual transactions.

	High	Low
2006		
First Quarter	$ 10.10	$ 5.60
Second Quarter	8.90	6.30
Third Quarter	7.90	6.40
Fourth Quarter	7.30	5.20
2005		
First Quarter	$ 14.90	$ 7.50
Second Quarter	12.10	8.40
Third Quarter	13.90	8.50
Fourth Quarter	11.10	8.50

Stock Performance Chart

The following chart compares the yearly percentage change in the cumulative total stockholder return on our Common Stock during the five years ended December 31, 2006 with the cumulative total return of the Standard and Poor s 500 Stock Index and of the Dow Jones U.S. Exploration and Production Index (formerly Dow Jones Secondary Oils Stock Index). The comparison assumes $100 was invested on December 31, 2001 in our Common Stock and in each of the foregoing indices and assumes reinvestment of dividends. We paid no dividends on our Common Stock during such five-year period.

Comparison of Five-Year Cumulative Total Return Among Crimson Exploration,

S&P 500 Index and the Dow Jones U.S. Exploration and Production Index

	Crimson	S&P 500 Index	DJ US Expl & Prod Index*
December 31, 2001	$ 100.00	$ 100.00	$ 100.00
December 31, 2002	$ 65.67	$ 76.63	$ 102.17
December 31, 2003	$ 62.69	$ 96.85	$ 133.90
December 31, 2004	$ 135.82	$ 105.56	$ 189.97
December 31, 2005	$ 134.33	$ 108.73	$ 314.06
December 31, 2006	$ 93.28	$ 123.54	$ 330.93

* formerly Dow Jones Secondary Oils Stock Index

Common Stock

We are authorized to issue up to 200.0 million shares of Common Stock, par value $0.001 per share. As of March 19, 2007, there were 3,338,749 shares of Common Stock issued and outstanding and held by approximately 242 record holders. Our Common Stock is traded over-the-counter (OTC) under the symbol CXPO . Fidelity Transfer Company, 1800 South West Temple, Suite 301, Box 53, Salt Lake City, Utah 84115, (801) 484-7222 is the transfer agent for the Common Stock.

Holders of Common Stock are entitled, among other things, to one vote per share on each matter submitted to a vote of shareholders and, in the event of liquidation, to share ratably in the distribution of assets remaining after payment of liabilities (including preferential distribution and dividend rights of holders of preferred stock). Holders of Common Stock have no cumulative rights. The holders of a majority of the outstanding shares of the Common Stock and Series G and H Preferred Stock (on an as converted basis) have the ability to elect all of the directors that the Series G does not elect. On February 28, 2005, the holders of the Series G Preferred Stock were granted the right to elect a majority of our Board of Directors.

Holders of Common Stock have no preemptive or other rights to subscribe for shares. Holders of Common Stock are entitled to such dividends as may be declared by the Board out of funds legally available therefor. We have never paid cash dividends on the Common Stock and do not anticipate paying any cash dividends in the foreseeable future.

Preferred Stock

Our board of directors is authorized, without further shareholder action, to issue preferred stock in one or more series and to designate the dividend rate, voting rights and other rights, preferences and restrictions of each such series. Our preferred stock is senior to our Common Stock regarding liquidation. The holders of the preferred stock do not have voting rights (except for the holders of the Series G and Series H Preferred Stock as discussed below) or preemptive rights, nor are they subject to the benefits of any retirement or sinking fund. We are authorized to issue up to 10.0 million shares of preferred stock.

As of March 19, 2007, there were a total of 103,220 shares of preferred stock issued and outstanding in four series: Series D, E, G and H Preferred Stock.

The Series D Preferred Stock is not entitled to dividends, nor is it redeemable; however it is convertible to Common Stock at anytime based on $80.00 per share of Common Stock. The 8,000 outstanding shares of Series D Preferred Stock are held by a former director and none have been converted. On a fully converted basis, the 8,000 shares of Series D Preferred Stock would convert to 50,000 shares of Common Stock.

The Series E Preferred Stock is entitled to receive dividends at the rate of 6% per share per annum, which may be deferred for the first four years after issuance and those deferred dividends will be convertible into Common Stock at the conversion price of $9.00 per share of Common Stock. The conversion price for the Series E Preferred Stock is otherwise based on $20.00 per share of Common Stock. The Series E Preferred Stock is held by a former director and none of the 9,000 outstanding shares has been redeemed or converted. On a fully converted basis, the 9,000 shares of Series E Preferred Stock would convert to 225,000 shares of Common Stock. The Series E Preferred Stock has an aggregate liquidation preference of $4.5 million, excluding accumulated and undeclared dividends, and is senior to all of our Common Stock and of equal preference with our Series D Preferred Stock and junior to our Series G Preferred Stock and Series H Preferred Stock.

The 81,000 shares of our Series G Preferred Stock bear a coupon of 8% per year and have an aggregate liquidation preference of $40.5 million, excluding accumulated and undeclared dividends. For the first four years after issuance, we may defer the payment of dividends on the Series G Preferred Stock and these deferred dividends will also be convertible into our Common Stock at $9.00 per share. In addition, the Series G Preferred Stock is entitled to vote on an as-converted basis with the holders of our Common Stock and, as a class, is entitled to nominate and elect a majority of the members of our Board of Directors. The Series G Preferred Stock is senior to all of our outstanding capital stock in liquidation preference.

The Series H Preferred Stock is required to be paid a dividend of 40 shares of Common Stock per Series H Preferred Stock share per year. In addition, the Series H Preferred Stock is convertible into Common Stock at a conversion price of $3.50 per share. The Series H Preferred Stock has an aggregate liquidation value of $2.6 million and is senior to all of our outstanding capital stock in liquidation preference other than its Series G Preferred Stock. There were 5,220 shares of Series H Preferred Stock outstanding at December 31, 2006.

Outstanding Options and Warrants.

At December 31, 2006, we had outstanding employee stock options, under our 1994 and 2004 Stock Option and Compensation Plans, to purchase 150,800 (all vested) shares of Common Stock at prices ranging from $4.50 to $18.10 per share and warrants to purchase 3,000 shares of Common Stock at $0.10 per share. On February 28, 2005 we established our 2005 Stock Incentive Plan and authorized the issuance of 2.7 million shares of Common Stock pursuant to awards under the plan, of which approximately 2.2 million (321,000 vested) shares were outstanding at December 31, 2006.

Recent Sales of Unregistered Securities.

As shown in the table that follows, during 2006 we issued Common Stock not registered under the Securities Act of 1933, as amended, in transactions we believe are exempt under Section 4(2) of the Act due to the limited number of persons involved and their relationship with us. No underwriters were used, and no underwriting discounts or commissions were paid in connection with the sales.

Date	Derivative	Holder(s)	Underlying Shares	Exercise/ Conversion Price	Consideration
3/01/06	Common Stock	Accredited Investors	26,234	NA	Bonus compensation to Company s Executive Officers
5/12/06	Common Stock	Accredited Investors	2,410	N/A	Director Compensation

*Received reduced number of shares in exchange for the exercise price.

ITEM 6. Selected Financial Data

The following table sets forth our selected consolidated financial data for the last five years ended as of December 31. This data should be read in conjunction with our Consolidated Financial Statements and the accompanying notes in Item 8, Item 1. Business and Item 7. Management s Discussion and Analysis of Financial Condition and Results of Operations included elsewhere in this Form 10-K.

	Year Ended December 31, 2006	2005	2004	2003	2002
Income Statement Data					
Operating revenues	$21,659,481	$17,682,808	$11,207,673	$11,010,723	$10,839,797
Net income (loss) from operations (1)	(2,458,685)	637,823	(476,264)	558,774	310,290
Net income (loss)	1,858,944	(3,543,239)	8,072,221	(3,024,426)	(4,502,313)
Dividends on preferred stock	(3,648,925)	(3,562,472)	(455,612)	(127,083)	(112,500)
Net income (loss) available to common shareholders	(1,789,981)	(7,105,711)	7,616,609	(3,151,509)	(4,614,813)
Net income (loss), per share of common stock, basic	$(0.55)	$(2.66)	$4.11	$(1.71)	$(2.46)
Weighted average number of shares of common stock outstanding	3,231,000	2,673,882	1,853,503	1,849,255	1,849,255

(1) Our adoption of SFAS 123r on January 1, 2006 resulted in expense of $3.7 million.

	2006	2005	2004	2003	2002
Balance Sheet Data					
Current assets	$4,231,983	$5,825,078	$3,808,878	$1,742,689	$2,353,046
Total assets	84,702,722	63,114,949	57,876,164	52,428,774	53,088,941
Current liabilities	10,932,155	6,855,735	37,249,217	44,619,652	43,998,566
Long-term liabilities	12,444,784	3,453,952	1,950,304	1,393,607	137,808
Other liabilities				591,467	1,128,993
Stockholders equity	$61,325,783	$52,805,262	$ 18,676,643	$ 5,824,648	$ 7,823,574

ITEM 7. Management s Discussion and Analysis of Financial Condition and Results of Operations

Overview

We are primarily engaged in the acquisition, development, exploitation and production of crude oil and natural gas, primarily in the onshore producing regions of the United States. Our focus is on increasing production from our existing properties through further exploitation, development and exploration, and on acquiring additional interests in undeveloped crude oil and natural gas properties. Our gross revenues are derived from the following sources:

1. **Oil and gas sales** that are proceeds from the sale of crude oil and natural gas production to midstream purchasers. This represents over 99% of our gross revenues.
2. **Operating overhead and other income** that consists of administrative fees received for operating crude oil and natural gas properties for other working interest owners and for marketing and transporting natural gas for those owners. This also includes earnings from other miscellaneous activities.

The following is a discussion of our consolidated results of operations, financial condition and capital resources. You should read this discussion in conjunction with our Consolidated Financial Statements and the Notes thereto contained elsewhere in this Form 10-K.

Results of Operations

Comparative results of operations for the periods indicated are discussed below.

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

Revenues

Oil and Gas Sales. Revenues from the sale of crude oil and natural gas, net of realized losses from our hedging instruments, increased approximately $3.9 million, or 22%, to $21.5 million in 2006 from $17.6 million in 2005. We realized a loss of $0.8 million on our oil hedges and a gain of $0.2 million on our gas hedges in 2006 compared to losses of approximately $2.4 million for oil and $1.5 million for gas in 2005. Hedging contracts in place for 2006 had better relative terms than those in effect in 2005. The increase in net revenues was due to higher realized crude oil and natural gas prices and slightly higher sales volumes.

For 2006, sales volumes were 184,881 barrels of crude oil and 1,542,423 mcf of natural gas, or 2,651,709 natural gas equivalents (mcfe) compared to 177,833 barrels of crude oil and 1,482,250 mcf of natural gas, or 2,549,248 mcfe in 2005. On a daily basis we produced an average of 7,265 mcfe in 2006 compared to a daily average of 6,984 mcfe in 2005.

Oil and gas prices are reported net of the realized effects of our hedging agreements. Prices realized in 2006 were $59.00 per bbl and $6.85 per mcf compared to $39.61 per bbl and $7.09 per mcf in 2005. Prices before the effects of the hedging agreements were $63.29 per bbl and $6.76 per mcf in 2006 compared to $53.49 per bbl and $8.08 per mcf in 2005.

Operating Overhead and Other Income. Revenues from these activities increased to $0.2 million in 2006 from $0.1 million in 2005 due to an increase in overhead reimbursements from non-operating partners.

Costs and Expenses

Lease Operating Expenses. Lease operating expenses increased $1.9 million, or 35%, to $7.5 million in 2006 from $5.6 million in 2005. The increase was due to higher production taxes from higher revenues, higher expense related to production enhancing costs incurred on producing wells and higher cost of goods and services prevalent in the industry.

On a per unit basis, expenses increased to $2.84 per mcfe in 2006 from $2.19 per mcfe in 2005 on the higher costs and lower production.

Exploration Expense. Exploration expense was $0.4 million in both 2006 and 2005 as we acquired seismic data for prospect generation and made a delay rental payment in association with our Culberson County leases. We will continue to invest capital in seismic data and lease rentals costs as we develop and expand our internal exploratory prospect generation capability.

Depreciation, Depletion and Amortization (DD&A). DD&A expense for 2006 was $4.0 million compared to $3.1 million for 2005, due primarily to the increase in the DD&A rate per unit to $1.49 per mcfe in 2006 from $1.23 per mcfe in 2005.

Dry Holes, Abandonment Costs and Impaired Assets. Dry hole, abandonment and impairment expense was $3.2 million in 2006 compared to $4.1 million in 2005. The expense in 2006 included an impairment of $3.1 million on our Iola property due to the expiration of certain undeveloped leasehold interests and the impairment of proved reserves related to declining performance and the lower gas prices upon which the proved reserves were valued. Included in the 2005 expense were two exploratory dry holes.

General and Administrative (G&A) Expenses. Our G&A expenses increased approximately $5.0 million, or 131%, to $8.7 million in 2006 compared to $3.8 million in 2005, primarily due to the non-cash stock option expense of $3.7 million ($1.39 per mcfe) related to our adoption of SFAS 123R on January 1, 2006. On a per unit basis, expenses increased to $3.29 per mcfe in 2006 from $1.48 per mcfe in 2005.

Interest Expense. Interest expense decreased to $0.1 million in 2006 compared to $1.3 million in 2005, primarily due to the retirement of debt in our February 2005 recapitalization.

Other Financing Costs. Other financing costs were $0.2 million in 2006 compared to $2.0 million in 2005. The expense in 2006 was comprised primarily of the amortization of capitalized costs associated with our revolving senior credit facility we entered into in July 2005 and our subordinate credit agreement we entered into in August 2006 and fees related to the unused portion of the credit facilities. Costs in 2005 included the write-off of capitalized debt issuance costs associated with previous financings that were repaid with proceeds from the sale of the Series G Preferred Stock in February 2005.

Unrealized Gain/(Loss) on Derivative Instruments. Unrealized gain or loss on derivative instruments is the change during the period in the mark-to-market exposure under our commodity price hedging instruments. This non-cash increase in earnings for 2006 was approximately $6.1 million compared with a non-cash expense of $1.6 million for 2005. This expense will vary period to period and will be a function of the hedges in place, the strike prices of those hedges and the current NYMEX prices at each balance sheet date.

Income Taxes. Our net income before taxes was $3.3 million for 2006. After adjusting for permanent tax differences, we recorded $1.4 million in income tax expense. We reported a net loss before taxes of $4.3 million in 2005 resulting in an income tax benefit of $0.8 million.

Dividends on Preferred Stock. Dividends on preferred stock remained flat at $3.6 million for 2006 and 2005. Dividends in 2006 included $3.2 million on the Series G Preferred Stock, $0.1 million on the Series H Preferred Stock and $0.3 million on the Series E Preferred Stock. Dividends for preferred stock in 2005 included $2.7 million on the Series G Preferred Stock, $0.2 million on the Series H Preferred Stock, $0.3 million on the Series E Preferred Stock and $0.4 million for the other series of preferred stock previously issued by the Company and/or its subsidiaries and retired as part of the February 28, 2005 recapitalization.

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

Revenues

Oil and Gas Sales. Revenues from the sale of crude oil and natural gas, net of realized losses from the hedging instruments, increased 58% to $17.6 million in 2005 from $11.1 million in 2004. Losses realized on our hedges during 2005 were $2.5 million for oil and $1.5 million for gas compared to $1.3 million for oil and $0.6 million for gas in 2004. The increase in revenues was due to higher oil and gas sales volumes and higher crude oil and natural gas prices, as further described below.

In 2005, our sales volumes were 177,833 barrels of crude oil and 1,482,250 Mcf of natural gas, or 2,549,248 natural gas equivalents (mcfe), compared to 173,865 barrels of crude oil and 1,033,433 Mcf of natural gas, or 2,076,623 Mcfe in 2004. On a daily basis we produced an average of 6,984 Mcfe in 2005 compared to a daily average of 5,689 Mcfe in 2004. Higher sales volumes were a direct result of the development program we began in late 2004 and continued in 2005. The developmental program included our drilling and completing 2 new gas wells in east Texas in early 2005, the completion of workover and facility projects at Grand Lake and Lacassine fields in southwest Louisiana, and the workover of wells in east and south Texas. Volume increases generated through our development program not only offset the loss of production from property sales in 2004, but also allowed us to achieve the 23% increase in production despite the shut-in of approximately 4,500 Mcfepd from the effects of Hurricane Rita during parts of September and October, with production still approximately 12% below pre-hurricane levels due to delays in getting water disposal facilities back fully operational. We estimate, on average, that the average daily rate for 2005 was negatively impacted by 400 Mcfed.

Oil and Gas prices are reported net of the realized effect of our hedging agreements. Prices realized were $39.61 per Bbl and $7.09 per Mcf in 2005 compared to $31.63 per Bbl ad $5.42 per Mcf in 2004. Prices before the effects of the hedging agreements were $53.49 per Bbl and $8.08 per Mcf in 2005 compared to $38.82 per Bbl and $5.99 per Mcf in 2004.

Operating Overhead and Other Income. Revenues from these activities increased 22% to $131,000 in 2005 from $107,000 in 2004 due to higher transportation fees resulting from higher volume.

Costs and Expenses

Lease Operating Expenses. Overall, operating expenses increased 14% to $5.6 million in 2005 from $4.9 million in 2004. The increase was primarily due to higher production taxes as a result of increased sales volumes and commodity prices, and to a lesser extent, general price increases for goods and services industry wide.

On a per unit basis, expenses decreased to $2.19 per Mcfe in 2005 from $2.35 per Mcfe in 2004. This decrease in lifting cost was due to the higher sales volume, not offset by higher lifting costs.

Exploration Expense. Exploration expense was $0.4 million in 2005 as we began to acquire seismic data as part of our strategy to develop an internal exploratory prospect generation capability. No exploration costs were incurred in 2004 as we focused our capital program on the development of its proved reserves.

Depreciation, Depletion and Amortization (DD&A). DD&A increased 43% to $3.1 million in 2005 from $2.2 million in 2004, due to higher production volumes, and an increase in the DD&A rate per unit to $1.23 per Mcfe in 2005 from $1.05 per Mcfe in 2004. The increase in our DD&A rate in 2005 resulted from a capital expenditure plan consisting primarily of development projects that increased production and cash flow, but added no reserves.

Dry Holes, Abandonment Costs and Impaired Assets. Dry hole, abandonment and impairment expense was $4.1 million in 2005 compared to $0.5 million in 2004. Included in the 2005 expense were two exploratory dry holes, one of which was plugged and abandoned and one of which was still being evaluated. The Mustang Island 749 #1 well was technically still being evaluated in 2005. However, we did not believe that it would ultimately be determined to be economical, therefore, included in this expense for 2005, was an impairment of $3.2 million. The 2004 expense was comprised primarily of leasehold abandonment costs.

General and Administrative (G&A) Expenses. G&A expenses increased 87%, to $3.8 million in 2005 from $2.0 million in 2004, due to higher salaries resulting from additions to our management team to carry out our post recapitalization growth plan. On a per unit basis, expenses increased to $1.48 per Mcfe in 2005 from $0.92 per Mcfe in 2004.

Interest Expense. Interest expense decreased 69% to $1.3 million in 2005 from $4.2 million in 2004, primarily due to the retirement of debt associated with our February 2005 recapitalization.

Other Financing Costs. Other financing costs were $2.0 million in 2005 compared with $1.5 million in 2004. Costs in 2005 included the write-off of previously capitalized debt issuance costs associated with previous financings that were repaid with proceeds from the sale of the Series G Preferred Stock in February 2005. The expense in 2004 was comprised primarily of the amortization of capitalized costs associated with the financings repaid in February 2005.

Unrealized (Gain)/Loss on Derivative Instruments. Unrealized gain or loss on derivative instruments is the change during the year in the mark-to-market exposure under our commodity price hedging instruments. This non-cash expense for 2005 was $1.6 million compared to $1.5 million for 2004. This expense will vary period to period, and will be a function of the hedges in place, and the strike prices of those hedges, at each balance sheet date.

Income Taxes. Income tax benefit for 2005 was $0.8 million compared to a benefit of $3.2 million for 2004.

Dividends on Preferred Stock. Dividends on preferred stock were $3.6 million in 2005 compared to $0.5 million in 2004. Dividends in 2005 included $2.7 million on the Series G Preferred Stock, $0.2 million on the Series H Preferred Stock, $0.3 million on the Series E Preferred Stock and $0.4 million for the other series of preferred stock previously issued by the Company and/or its subsidiaries and retired as part of the February 28, 2005 recapitalization. Dividends on preferred stock for 2004 included $0.2 million on the Series E Preferred Stock and $0.3 million for the other series of preferred stock previously issued by the Company and/or its subsidiaries and retired as part of the February 28, 2005 recapitalization.

Year Ended December 31, 2004 Compared to Year Ended December 31, 2003

Revenues

Oil and Gas Sales. Our operating revenues from the sale of crude oil and natural gas increased by 2% to $11.1 million in 2004 from $10.8 million in 2003. Revenue increases due to higher oil and natural gas sales prices were substantially offset by a 17% decrease in sales volumes, 12% of which was due to normal oil and gas production declines and 5% due to property sales.

Operating Overhead and Other Income. Revenues from these activities decreased 36%, to $107,000 in 2004 from $166,000 in 2003, primarily due to a one-time $58,000 contract settlement received in 2003 and lower pipeline volumes resulting in less transportation revenue.

Costs and Expenses

Lease Operating Expenses. Lease operating expenses decreased 12% to $4.9 million in 2004 from $5.5 million in 2003, 5% was due to lower variable costs on lower production volumes and 7% due to property sales. On a per Mcfe basis, costs increased to $2.35 per Mcfe in 2004 from $2.19 in 2003 because of lower volume and higher vendor prices.

Depreciation, Depletion and Amortization (DD&A). DD&A decreased 2% to $2.2 million in 2004 from $2.2 million in 2003, due to lower production volumes. On a per Mcfe basis, the DD&A rate increased to $1.05 per Mcfe in 2004 from $0.88 in 2003 due to higher than anticipated development costs.

Dry Holes, Abandoned Property and Impaired Assets. The cost of dry holes, abandoned property and impaired assets expense in 2004 was $0.5 million compared to $0.4 million in 2003. The abandoned property was due to a lack of capital to complete projects resulting in the loss of leases.

General and Administrative (G&A) Expenses. G&A expenses decreased 11% to $2.0 million in 2004 from $2.3 million in 2003 due to expenses incurred in 2003 associated with financing efforts that were not culminated.

Interest Expense. Interest expense increased 24% to $4.2 million in 2004 from $3.4 million in 2003. In April 2004 we retired debt of approximately $27.6 million carrying an interest rate of prime plus 3.5% and replaced it with debt of approximately $18.0 million that carried an interest rate of prime plus 11.0%. Also, included in 2004 is non-cash interest expense of approximately $0.4 million resulting from the discounting on a note payable issued in 2004.

Other Financing Costs. Other financing costs increased 47% to $1.5 million in 2004 from $1.0 million in 2003. In 2003, we recorded an expense of $1.0 million to account for the issuance of 2,000 shares of our preferred stock in conjunction with the financial agreement on the retired debt referred to above. The expense in 2004 represents the amortized portion of loan fees associated with the refinancing of debt referred to above.

Loss on Sale of Property and Equipment. We recorded a loss on sale of property and equipment of $2.0 million in 2004 as compared to $20,000 in 2003.

Unrealized Gain (Loss) on Derivative Instruments. The estimated future fair value of derivative instruments at December 31, 2004 resulted in an estimated unrealized loss of $1.5 million in 2004 compared to an unrealized gain of $0.5 million in 2003. Estimated unrealized gain/loss on oil and gas price hedges in place on a particular balance sheet date is based on a mark-to-market calculation based on a market price forecast on the balance sheet date compared to the prices provided for in the derivative instruments.

Forgiveness of Debt. In 2004 we had $12.5 million in debt forgiven as the result of debt refinancing in April, 2004.

Income Taxes. Income tax benefit for 2004 was $3.2 million compared to zero for 2003.

Dividends on Preferred Stock. In 2004, a dividend on preferred stock due was $0.5 million. In 2003 dividends on preferred stock due was $0.1 million. The board of directors did not declare any dividends to be paid.

Critical Accounting Policies

The factors which most significantly affect our results of operations are (1) the sales price of crude oil and natural gas, (2) the level of total sales volumes of crude oil and natural gas, (3) the cost and efficiency of operating our own properties, (4) depletion and depreciation of oil and gas property costs and related equipment (5) the level of and interest rates on borrowings, (6) the level and success of acquiring or finding new reserves, and the acquisition, finding and development costs incurred in adding these reserves, and (7) the adoption of changes in accounting rules.

Successful Efforts Method

We use the successful efforts method of accounting for oil and gas producing activities. Costs to acquire mineral interests in oil and gas properties, to drill and equip exploratory wells that find proved reserves, and to drill and equip development wells are capitalized. Costs to drill exploratory wells that do not find proved reserves, delay rentals and geological and geophysical costs are expensed (except those costs used to determine a drill site location).

Depletion and Depreciation

We consider depletion and depreciation of oil and gas properties and related support equipment to be critical accounting estimates, based upon estimates of total recoverable oil and gas reserves. The estimates of oil and gas reserves utilized in the calculation of depletion and depreciation are estimated in accordance with guidelines established by the Society of Petroleum Engineers, the Securities and Exchange Commission and the Financial Accounting Standards Board, which require that reserve estimates be prepared under existing economic and operating conditions with no provision for price and cost escalations over prices and costs existing at year end, except by contractual arrangements. We emphasize that reserve estimates are inherently imprecise. Accordingly, the estimates are expected to change as more current information becomes available. Our policy is to amortize capitalized oil and gas costs on the unit of production method, based upon these reserve estimates. It is reasonably possible that the estimates of future cash inflows, future gross revenues, the amount of oil and gas reserves, the remaining estimated lives of the oil and gas properties, or any combination of the above may be increased or reduced in the near term. If reduced, the carrying amount of capitalized oil and gas properties may be reduced materially in the near term.

Asset Retirement Obligations

In 2003, we adopted the Statement of Financial Accounting Standards No. 143, Asset Retirement Obligations (SFAS 143) which requires us to recognize an estimated liability for the plugging and abandonment of our oil and

gas wells and associated pipelines and equipment. The liability and the associated increase in the related long-lived asset are recorded in the period in which our asset retirement obligation (ARO) is incurred. The liability is accreted to its present value each period and the capitalized cost is depreciated over the useful life of the related asset.

The estimated liability is based on historical experience in plugging and abandoning wells, estimated remaining lives of those wells based on reserves estimates and federal and state regulatory requirements. The liability is discounted using an assumed credit-adjusted risk-free rate.

Revisions to the liability could occur due to changes in estimates of plugging and abandonment costs, changes in the risk-free rate or remaining lives of the wells, or if federal or state regulators enact new plugging and abandonment requirements. At the time of abandonment, we recognize a gain or loss on abandonment to the extent that actual costs do not equal the estimated costs.

At the end of 2006, we increased our ARO to include the new wells drilled in our Madisonville-Rodessa project. At the same time, the original cost assumptions for existing fields were reevaluated due to certain fields having wells plugged and abandoned in 2006 which caused losses to be incurred as the actual costs were higher than the original estimated costs. It was determined at that time that the costs associated with abandonment have increased significantly due to higher service costs prevalent in the industry, and the timing of settling the obligations was also revised.

Derivative Instruments

At the end of each reporting period we are required by SFAS 133 Accounting for Derivative Instruments and Hedging Activities, to record on our balance sheet the mark-to-market valuation of our derivative instruments. The estimated change in fair value of the derivatives is reported in Other Income and Expense as unrealized (gain) loss on derivative instruments.

Recent Accounting Pronouncements

In September 2006, the Securities and Exchange Commission staff (SEC) issued SAB 108. SAB 108 was issued to provide consistency to how companies quantify financial statement misstatements. SAB 108 establishes an approach that requires companies to quantify misstatements in financial statements based on effects of the misstatement on both the consolidated balance sheet and statement of operations and the related financial statement disclosures. Additionally, companies must evaluate the cumulative effect of errors existing in prior years that previously had been considered immaterial. We adopted SAB 108 in connection with the preparation of our annual financial statements for the year ended December 31, 2006 and found no adjustments necessary.

In September 2006, the FASB issued SFAS No. 157, *Fair Value Measurements* (SFAS No. 157). SFAS No. 157 defines fair value, establishes a framework for measuring fair value in generally accepted accounting principles and expands disclosures about fair value measurements. SFAS No. 157 does not require any new fair value measurements, rather, its application will be made pursuant to other accounting pronouncements that require or permit fair value measurements. SFAS No.157 is effective for financial statements issued for fiscal years beginning after November 15, 2007, and interim periods within those years. The provisions of SFAS No. 157 are to be applied prospectively upon adoption, except for limited specified exceptions. We are evaluating the requirements of SFAS No. 157 and do not expect the adoption to have a material impact on our Consolidated Balance Sheet or Statement of Operations.

In June 2006, the Financial Accounting Standards Board (FASB) issued Interpretation No.48, Accounting for Uncertainty in Income Taxes-an interpretation of FASB Statement No. 109 (FIN 48). FIN 48 clarifies the accounting for uncertainty in income taxes recognized in a company s financial statements in accordance with FASB Statement No. 109, Accounting for Income Taxes. It prescribes a recognition threshold and measurement attribute for the financial statement recognition and measurement of a tax position taken or expected to be taken in a tax return. FIN 48 also provides guidance on derecognition, classification, interest and penalties, accounting in interim periods, disclosure and transition. FIN 48 is effective for fiscal years beginning after December 15, 2006 and will be adopted by us on January 1, 2007. We have not been able to complete our evaluation of the impact of adopting FIN 48 and as a result, are not able to estimate the effect the adoption will have on our financial position

and results of operations, including our ability to comply with current debt covenants.

Texas House Bill 3 (HB3), which was signed into law in May, 2006, provides a comprehensive change in the method of business taxation in Texas. HB3 eliminates the taxable capital and earned surplus components of the existing Texas franchise tax and replaces these components with a taxable margin tax. This change is effective for tax reports filed on or after January 1, 2008 (which are based upon 2007 business activity) and results in no impact on our current Texas income tax. We are required to include, in income, the impact of HB3 on deferred state income taxes during the period which includes the date of enactment. Based upon the available information regarding the proposed implementation of this new tax, we have determined that no significant change in the amount of net deferred state income taxes is needed.

Contractual Obligations

The following table provides information about our contractual cash obligations as of December 31, 2006:

	Long-term debt	Operating leases	Asset retirements
2007	$ 91,093	$ 191,488	$ 185,414
2008	32,029	517,725	
2009	8,379,931	517,725	136,767
2010	3,033	540,125	145,182
2011		551,325	224,895
More than 5 years		1,148,594	3,522,947
Total	$ 8,506,086	$ 3,466,982	$ 4,215,205

Liquidity and Capital Resources

At December 31, 2006, our current liabilities exceeded our current assets by approximately $6.7 million, while at December 31, 2005 our current liabilities exceeded our current assets by $1.0 million. At December 31, 2006 we had $16.5 million available on our revolving line of credit and $15.0 million available under our subordinate credit agreement. During 2006, we generated $14.3 million in cash flow from operations compared to $3.5 million in 2005. We believe cash flow, along with available borrowings under our credit agreements, will be sufficient to fund our daily operations, debt service and planned capital development program in 2007. Our level of exploratory capital expenditures for 2007 will be determined based on available cash flow and other appropriate sources of available capital.

Financial Recapitalization

On February 28, 2005, we sold in a private placement, 81,000 shares of our Series G Preferred Stock to OCMGW for an aggregate offering price of $40.5 million. GulfWest Oil and Gas Company (GWOG), a subsidiary of the Company, issued, in a private placement, 2,000 shares of our Series A Preferred Stock, having a liquidation preference of $1.0 million, to OCMGW for $1.5 million. Net proceeds of the offerings of approximately $38.2 million after expenses were used for the repayment of substantially all of our outstanding debt and other past due liabilities and for general corporate purposes.

The Series G Preferred Stock bears a coupon of 8% per year, has an aggregate liquidation preference of $40.5 million (excluding accumulated undeclared dividends), is convertible into common stock at $9.00 per share and is senior to all of our capital stock. For the first four years after issuance, we may defer the payment of dividends on the Series G Preferred Stock and these deferred dividends will also be convertible into our common stock at $9.00 per share. In addition, the Series G Preferred Stock is entitled to nominate and elect a majority of the members of our Board of Directors.

In connection with these recapitalization transactions, the terms of the Series A Preferred Stock were amended such that by March 15, 2005, all such stock would either convert into a newly created Series H Preferred Stock on a one for one basis or into common stock at a conversion price of $3.50 per share. The Series H Preferred Stock is required to be paid a dividend of 40 shares of common stock per share of Series H Preferred Stock per year. In April, 2005, an additional 1,250 shares converted into 178,572 of common stock. The outstanding Series H

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Preferred Stock has an aggregate liquidation preference of approximately $2.6 million. The Series H Preferred Stock is senior to all of our capital stock other than Series G Preferred Stock.

In addition, we amended the terms of our 9,000 shares of Series E Preferred Stock such that the coupon of 6% per year may be deferred for the next four years and these deferred dividends will be convertible into common stock at a conversion price of $9.00 per share. The original liquidation preference of the Series E Preferred Stock of $500 per share remains convertible into common stock at $20.00 per share. The Series E Preferred Stock has an aggregate liquidation preference of $4.5 million (excluding accumulated undeclared dividends), and is senior to all of our common stock, of equal preference with our Series D Preferred Stock as to liquidation and junior to our Series G and Series H Preferred Stock.

On May 17, 2005, we executed a promissory note for the benefit of OCMGW, in the principal amount of $1.0 million, payable on the earlier of July 17, 2005 or the day on which we are able to make draws under a credit facility under which greater than $1.0 million may be borrowed. Interest on the unpaid principal accrued at 4.59% per annum. We repaid the note in full on July 19, 2005 from borrowings under our new $100.0 million senior secured revolving credit facility.

On July 15, 2005, we entered into a $100.0 million senior secured revolving credit facility with Wells Fargo Bank, National Association, also referred to as our Senior Credit Agreement. Borrowings under the credit facility are subject to a borrowing base limitation based on our current proved oil and gas reserves. The original borrowing base was set at $20.0 million and is subject to semi-annual redeterminations. The facility is secured by a lien on all our assets, and the assets of our subsidiaries, as well as a security interest in the stock of all our subsidiaries. The credit facility had an original term of three years, and all principal amounts, together with all accrued and unpaid interest, were due and payable in full on June 30, 2008. Proceeds from extensions of credit under the facility will be for acquisitions of oil and gas properties and for general corporate purposes. The facility also provides for the issuance of letters-of-credit up to a $3.0 million sub-limit. We incurred $0.3 million in issuance costs associated with the credit facility which are being amortized over its life. In connection with the Subordinate Credit Agreement discussed in Item 1 Our Business Recent Developments , we amended our Senior Credit Agreement, primarily to provide for the Subordinate Credit Agreement but also to provide for a redetermined borrowing base of $25.0 million and to extend the maturity date of the facility to August 31, 2009.

Advances under the facility will be in the form of either base rate loans or Eurodollar loans. The interest rate on the base rate loans fluctuates based upon the higher of (1) the lender s prime rate and (2) the Federal Funds rate, plus a margin of 0.50%, plus an additional margin of between 0.0% and 0.5% depending on the percent of the borrowing base utilized at the time of the credit extension. The interest rate on the Eurodollar loans fluctuates based upon the rate at which Eurodollar deposits in the London Interbank market (Libor) are quoted for the maturity selected, plus a margin of 1.25% to 2.00% depending on the percent of the borrowing base utilized at the time of the credit extension. Eurodollar loans of one, three and nine months may be selected by us. A commitment fee of 0.375% on the unused portion of the borrowing base will accrue, and be payable quarterly in arrears. Our weighted average interest rate at December 31, 2006 was 6.89%.

We believe that we have sufficient liquidity through our cash from operations and borrowing capacity under our senior and subordinate revolving credit facilities to meet our short-term and long-term normal recurring operating needs, derivative obligations, debt service obligations, contingencies and anticipated capacity expenditures.

Inflation and Changes in Prices.

While the general level of inflation affects certain costs associated with the petroleum industry, factors unique to the industry result in independent price fluctuations. Such price changes have had, and will continue to have a material effect on our operations; however, we cannot predict these fluctuations.

The following table indicates the average quarterly crude oil and natural gas prices received over the last three years. Average prices per MCF equivalent, computed by converting oil production to natural gas equivalents at the rate of 6 *Mcf* per barrel, indicate the composite impact of changes in crude oil and natural gas prices.

	Average Prices(1) Crude Oil and Liquids (per Bbl)	Natural Gas (per Mcf)	Per Equivalent MCF
2006			
First	$ 58.11	$ 7.71	$ 8.63
Second	60.48	6.61	8.09
Third	60.85	6.72	8.07
Fourth	56.71	6.56	7.71
2005			
First	$ 35.84	$ 5.91	$ 5.94
Second	37.26	6.15	6.18
Third	38.58	7.46	7.03
Fourth	47.98	9.09	8.63
2004			
First	$ 27.97	$ 4.87	$ 4.76
Second	30.41	5.34	5.20
Third	32.72	5.44	5.45
Fourth	35.32	5.97	5.93

(1) Average sales price are shown net of the settled amounts of our oil and gas hedge contracts.

ITEM 7A. Qualitative and Quantitative Disclosures about Market Risk.

The following market rate disclosures should be read in conjunction with our financial statements and notes thereto beginning on Page F-1 of this Annual Report on Form 10-K. All of our financial instruments are for purposes other than trading. We only enter into derivative financial instruments in conjunction with our oil and gas sales price hedging activities. Hypothetical changes in interest rates and prices chosen for the following stimulated sensitivity effects are considered to be reasonably possible near-term changes generally based on consideration of past fluctuations for each risk category. It is not possible to accurately predict future changes in interest rates and product prices. Accordingly, these hypothetical changes may not be an indicator of probable future fluctuations.

Interest Rate Risk

We are exposed to interest rate risk on debt with variable interest rates. At December 31, 2006, we carried variable rate debt of approximately $8.5 million. Assuming a one percentage point change at December 31, 2006 on our variable rate debt, the annual pretax net income or loss would change by approximately $85,000.

Commodity Price Risk

In the past we have entered into, and may in the future enter into, certain derivative arrangements with respect to portions of our oil and natural gas production to reduce our sensitivity to volatile commodity prices. During 2006 and 2005, we entered into price swaps and put agreements with financial institutions. We believe that these derivative arrangements, although not free of risk, allow us to achieve a more predictable cash flow and to reduce exposure to price fluctuations. However, derivative arrangements limit the benefit to us of increases in the prices of crude oil and natural gas sales. Moreover, our derivative arrangements apply only to a portion of our production and provide only partial price protection against declines in price. Such arrangements may expose us to risk of financial loss in certain circumstances. We expect that the monthly volume of derivative arrangements will vary from time to time. We continuously reevaluate our price hedging program in light of increases in production, market conditions,

commodity price forecasts, and capital spending and debt service requirements.

The following derivatives were in place at December 31, 2006.

Crude Oil			**Volume/ Month**	**Price/ Unit**	**Fair Value**
Jan 2007	Dec 2007	Collar	3,000 Bbls	Floor $45.00-$59.45 Ceiling	(263,241)
Jan 2007	Dec 2007	Collar	5,100 Bbls	Floor $69.64-$84.35 Ceiling	405,118
Jan 2008	Dec 2008	Swap	6,500,Bbls	$76.40	642,372
Jan 2009	Dec 2009	Swap	5,200 Bbls	$74.20	389,732
Jan 2010	Dec 2010	Swap	4,250 Bbls	$72.32	253,578
Jan 2011	Dec 2011	Swap	3,300 Bbls	$70.74	157,211
Natural Gas					
Jan 2007	Dec 2007	Collar	20,000 MMBTU	Floor $6.00-$6.95 Ceiling	(69,458)
Jan 2007	Dec 2007	Collar	37,000 MMBTU	Floor $8.00-$11.84 Ceiling	628,440
Jan 2008	Dec 2008	Swap	47,000 MMBTU	$8.97	475,933
Jan 2009	Dec 2009	Swap	36,000 MMBTU	$8.32	182,434
Jan 2010	Dec 2010	Swap	29,000 MMBTU	$7.88	131,769
Total fair value asset					2,933,888
Current portion					(700,088)
Noncurrent portion					2,233,800

We also had the following put options in place at December 31, 2006, for the months reflected.

Crude Oil		**Monthly Volume**	**Price per Bbl**
Nov 2006	Apr 2007	5,000 Bbls	$25.75

The value of these put options was minimal.

At the end of each reporting period we are required by SFAS 133 Accounting for Derivative Instruments and Hedging Activities, to record on our balance sheet the mark-to-market valuation of our derivative instruments. We recorded a net asset for derivative instruments at December 31, 2006 of $2.9 million and a net liability of $3.1 million at December 31, 2005. As a result of these agreements, we recorded a non-cash increase in earnings, for unsettled contracts, of $6.1 million, a non-cash charge of $1.6 million and a non-cash charge of $1.5 million for the twelve month periods ended December 31, 2006, 2005 and 2004, respectively. The estimated change in fair value of the derivatives is reported in Other Income and Expense as unrealized (gain) loss on derivative instruments.

For settled contracts, we realized losses, reflected as reductions in oil and gas revenues, of $0.8 million, and $3.9 million and $1.8 million for the twelve month periods ended December 31, 2006, 2005 and 2004, respectively.

ITEM 8. Financial Statements and Supplementary Data

Information with respect to this Item 8 is contained in our financial statements beginning on Page F-1 of this Annual Report on Form 10-K.

ITEM 9. Changes In and Disagreements with Accountants and Accounting and Financial Disclosure

None

ITEM 9A. Controls and Procedures

Our president and chief executive officer and our chief financial officer have concluded, based on their evaluation as of the end of the period covered by this Form 10-K, that our disclosure controls and procedures, as defined under Rules 13a-15(e) and 15d-15(e) of the Securities Exchange Act of 1934, as amended, are effective to ensure that information we are required to disclose in the reports we file or submit under the Exchange Act is recorded, processed, summarized and reported within the time periods specified in the SEC s rules and forms, and that our disclosure controls and procedures are effective to ensure that information we are required to disclose in such reports is accumulated and communicated to management, including our president and chief executive officer and our chief financial officer, as appropriate to allow timely decisions regarding required disclosure.

During the period covered by this report, there has been no change in our internal controls over financial reporting that materially affected, or is reasonably likely to material affect, these controls.

ITEM 9B. Other Information

None

PART III

ITEM 10. Directors and Executive Officers of the Registrant

Information regarding directors and executive officers of the registrant is incorporated herein by reference to our Proxy Statement to be filed with the SEC pursuant to the Exchange Act within 120 days of the end of our fiscal year ended December 31, 2006.

ITEM 11. Executive Compensation

Information regarding executive compensation is incorporated herein by reference to our Proxy Statement to be filed with the SEC pursuant to the Exchange Act within 120 days of the end of our fiscal year ended December 31, 2006.

ITEM 12. Ownership of Certain Beneficial Owners and Management and Related Stockholder Matters

Information regarding security ownership of certain beneficial owners and management and related stockholder matters is incorporated herein by reference to our Proxy Statement to be filed with the SEC pursuant to the Exchange Act within 120 days of the end of our fiscal year ended December 31, 2006.

ITEM 13. Certain Relationships and Related Transactions

Information regarding certain relationships and related transactions is incorporated herein by reference to our Proxy Statement to be filed with the SEC pursuant to the Exchange Act within 120 days of the end of our fiscal year ended December 31, 2006.

ITEM 14. Principal Accountant Fees and Services

Information regarding principal accountant fees and services is incorporated herein by reference to our Proxy Statement to be filed with the SEC pursuant to the Exchange Act within 120 days of the end of our fiscal year ended December 31, 2006.

GLOSSARY OF INDUSTRY TERMS AND ABBREVIATIONS

The following are definitions of certain industry terms and abbreviations used in this report:

Bbl. Barrel.

Gross Acres or Gross Wells. The total acres or wells, as the case may be, in which a *working interests* is owned.

Horizontal Drilling. High angle directional drilling with lateral penetration of one or more productive reservoirs.

Mcf. One thousand cubic feet.

Mcfe. Natural gas equivalent. One barrel of oil is equivalent to six Mcf.

Net Acres or Net Wells. The sum of the fractional *working interests* owned in *gross acres* or *gross wells*.

Overriding Royalty Interest. The right to receive a share of the *proceeds of production* from a well, free of all costs and expenses, except transportation.

Present Value. The pre-tax present value, discounted at 10%, of future net cash flows from estimated proved reserves, calculated holding prices and costs constant at amounts in effect on the date of the report (unless such prices or costs are subject to change pursuant to contractual provisions) and otherwise in accordance with the Commission s rules for inclusion of oil and gas reserve information in financial statements filed with the Commission.

Proceeds of Production. Money received (usually monthly) from the sale of oil and gas produced from producing properties.

Producing Properties. Properties that contain one or more wells that produce oil and/or gas in paying quantities (i.e., a well for which proceeds from production exceed operating expenses).

Productive Well. A well that is producing oil or gas or that is capable of production.

Prospect. A lease or group of leases containing possible reserves, capable of producing crude oil, natural gas, or natural gas liquids in commercial quantities, either at the time of acquisition, or after vertical or horizontal drilling, completion of *workovers*, *recompletions*, or operational modifications.

Proved Reserves. Estimated quantities of crude oil, natural gas, and natural gas liquids that geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known *reservoirs* under existing economic conditions; i.e., prices and costs as of the date the estimate is made. *Reservoirs* are considered proved if either actual production or a conclusive formation test supports economic production.

The area of a reservoir considered proved includes:

a. That portion delineated by drilling and defining by gas-oil or oil-water contacts, if any; and
b. The immediately adjoining portions not yet drilled but which can be reasonably judged as economically productive on the basis of available geological and engineering data. In the absence of information on fluid contacts, the lowest known structural occurrence of hydrocarbons controls the lower proved limit of the reservoir.

Reserves which can be produced economically through application of improved recovery techniques (such as fluid injection) are included in the proved classification when successful testing by a pilot project, or the operation of an installed program in the reservoir, provides support for the engineering analysis on which the project or program was based.

Proved Reserves do not include:

a. *Oil that may become available from known reservoirs but is classified separately as indicated additional reserves ;*

b. *Crude oil, natural gas, and natural gas liquids, the recovery of which is subject to reasonable doubt because of uncertainty as to geology, reservoir characteristics, or economic factors;*

c. *Crude oil, natural gas, and natural gas liquids that may occur in undrilled prospects; and*
d. *Crude oil, natural gas, and natural gas liquids that may be recovered from oil sales and other sources.*

Proved Developed Reserves. Reserves that can be expected to be recovered through existing wells with existing equipment and operating methods. Additional oil and gas expected to be obtained through the application of fluid injection or other improved recovery techniques for supplementing the natural forces and mechanisms of primary recovery should be included as *proved developed* only after testing by a pilot project or after operation of an installed program has confirmed through production response that increased recovery will be achieved.

Proved Undeveloped Reserves. Reserves that are expected to be recovered from new wells on undrilled acreage or from existing wells where a relatively major expenditure is required for *recompletion*. Reserves on undrilled acreage shall be limited to those drilling units offsetting productive units that are reasonably certain of production when drilled. Proved reserves for other units that have not been drilled can be claimed only where it can be demonstrated with certainty that there is continuity of production from the existing productive formation. Under no circumstances should estimates for *proved undeveloped reserves* be attributable to any acreage for which an application of fluid injection or other improved recovery technique is contemplated, unless such techniques have been proven effective by actual tests in the area and in the same reservoir.

Recompletion. The completion for production of an existing well bore in another formation from that in which the well has previously been completed.

Reservoir. A porous and permeable underground formation containing a natural accumulation of producible oil or gas that is confined by impermeable rock or water barriers and is individual and separate from other reservoirs.

Royalty. The right to a share of production from a well, free of all costs and expenses, except transportation.

Royalty Interest. An interest in an oil and gas property entitling the owner to a share of oil and natural gas production free of costs of production.

Standardized Measure. The present value, discounted at 10%, of future net cash flows from estimated proved reserves, after income taxes, calculated holding prices and costs constant at amounts in effect on the date of the report (unless such prices or costs are subject to change pursuant to contractual provisions) and otherwise in accordance with the Commission s rules for inclusion of oil and gas reserve information in financial statements filed with the Commission.

Waterflood. An engineered, planned effort to inject water into an existing oil reservoir with the intent of increasing oil reserve recovery and production rates.

Working Interest. The operating interest under a lease, the owner of which has the right to explore for and produce oil and gas covered by such lease. The full working interest bears 100 percent of the costs of exploration, development, production, and operation, and is entitled to the portion of gross revenue from the *proceeds of production* which remains after proceeds allocable to *royalty* and *overriding royalty interests* or other lease burdens have been deducted.

Workover. Rig work performed to restore an existing well to production or improve its production from the current existing *reservoir*.

PART IV

ITEM 15. Exhibits and Financial Statement Schedules.

(a) The following documents are filed as part of this Report:
(1) Financial Statements:
Consolidated Balance Sheets at December 31, 2006 and 2005.

Consolidated Statements of Operations for the years ended December 31, 2006, 2005 and 2004.

Consolidated Statements of Stockholders Equity for the years ended December 31, 2006, 2005 and 2004.

Consolidated Statements of Cash Flows for the years ended December 31, 2006, 2005 and 2004.

Notes to Consolidated Financial Statements, December 31, 2006, 2005 and 2004.

(2) Financial Statement Schedule:

Schedule II - Valuation and Qualifying Accounts

(3) Exhibits:

Number	Description
2.1	Agreement and Plan of Merger, dated March 14, 2006, among Crimson Exploration, Inc., Exploration Operating, Inc., Core Natural Resources, In
3.1	Certificate of Incorporation of the Registrant (incorporated by reference to Exhibit 3.1 of the Company s Current Report on Form 8-K filed July 5
3.2	Certificate of Designation, Preferences and Rights of Series D Preferred Stock (incorporated by reference to Exhibit 3.2 of the Company s Curren
3.3	Certificate of Designation, Preferences and Rights of Cumulative Convertible Preferred Stock, Series E (incorporated by reference to Exhibit 3.3 o
3.4	Certificate of Designation, Preferences and Rights of Series G Convertible Preferred Stock (incorporated by reference to Exhibit 3.4 of the Compa
3.5	Certificate of Designation, Preferences and Rights of Series H Convertible Preferred Stock (incorporated by reference to Exhibit 3.5 of the Compa
3.6	Bylaws of the Registrant (incorporated by reference to Exhibit 3.6 of the Company s Current Report on Form 8-K filed July 5, 2005)
3.7	Certificate of Amendment of Certificate of Incorporation (incorporated by reference to Appendix A to our Definitive Information Statement on Sc

ITEM 15. Exhibits and Financial Statement Schedules. (continued)

4.1	Letter Agreement by and among GulfWest Energy Inc., a Texas corporation, GulfWest Oil & Gas Company and the investors listed on the signature
4.2	Warrant Agreement made by and between GulfWest Energy Inc., and Highbridge/Zwirn Special Opportunities FUND, L.P., and Drawbridge Specia
4.3	Shareholders Rights Agreement between GulfWest Energy Inc. and OCM GW Holdings, LLC dated February 28, 2005 (incorporated by reference to
4.4	Omnibus and Release Agreement among GulfWest Energy Inc., OCM GW Holdings, LLC and those signatories set forth on the signature page there
4.5	Share Transfer Restriction Agreement between J. Virgil Waggoner and OCM GW Holdings, LLC, dated February 28, 2005 (incorporated by referen
4.6	Irrevocable Proxy executed by J. Virgil Waggoner dated February 28, 2005 (incorporated by reference to the exhibit 4.6 to our Annual Report on Fo
4.8	Letter Agreement among OCM GW Holdings, LLC, OCM Principal Opportunities Fund III, L.P., OCM Principal Opportunities Fund III GP, LLC, (
4.9	Subscription Agreement among OCM GW Holdings, LLC, Allan D. Keel and those individuals listed on the signature page thereto, dated February 2
4.10	First Amendment to Warrant Agreement among GulfWest Energy Inc., D.B. Zwirn Special Opportunities Fund, L.P. and Drawbridge Special Oppor
4.11	Registration Rights Agreement, dated March 20, 2006, among Crimson Exploration Inc. and the stockholders of Core Natural Resources, Inc. (incor
#10.1	Employment Agreement between Allan D. Keel and GulfWest Energy, Inc., dated February 28, 2005 (incorporated by reference to Exhibit 10.1 of th

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ITEM 15. Exhibits and Financial Statement Schedules. (continued)

#10.2	Employment Agreement between E. Joseph Grady and GulfWest Energy, Inc., dated February 28, 2005 (incorporated by reference to Exhibit 10.2 o
#10.3	GulfWest Oil Company 1994 Stock Option and Compensation Plan, amended and restated as of April 1, 2001 and approved by the shareholders on
#10.4	GulfWest Energy Inc. 2004 Stock Option Incentive Plan. (incorporated by reference to Exhibit 10.4 of the Company s Annual Report on Form 10-K
#10.5	GulfWest Energy Inc. 2005 Stock Option Incentive Plan (incorporated by reference to Exhibit 10.5 of the Company s Annual Report on Form 10-K
#10.6	Form of GulfWest Energy Inc. 2005 Stock Incentive Plan Stock Option Agreement (incorporated by reference to Exhibit 10.6 of the Company s An
10.7	Form of Warrant Agreement (incorporated by reference to Exhibit 4.10 of our Annual Report on Form 10-K for the year ended December 31, 2004)
#10.8	Form of Indemnification Agreement for directors and officers (incorporated by reference to Exhibit 10.3 to our Form 8-K, Reg. No. 001-12108, filed
10.9	Letter Agreement among D.B. Zwirn Special Opportunities Fund, LP, GulfWest Oil & Gas, and Drawbridge Special Opportunities Fund, LP, dated
10.10	Series G Subscription Agreement between GulfWest Energy Inc. and OCM GW Holdings, LLC dated February 28, 2005 (incorporated by reference
10.11	Series A Subscription Agreement between GulfWest Oil & Gas Company and OCW GW Holdings, LLC dated February 28, 2005 (incorporated by
10.12	Letter Agreement between W.L. Addison Investment, L.L.C., GulfWest Energy Inc., and Setex Oil and Gas Company dated February 24, 2005 exte

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ITEM 15. Exhibits and Financial Statement Schedules. (continued)

10.13	Letter Agreement between W.L. Addison Investment, L.L.C., GulfWest Energy Inc., and Setex Oil and Gas Company dated July 15, 2004 extendin
10.14	Oil and Gas Property Acquisition, Exploration and Development Agreement with Summit Investment Group-Texas, L.L.C. effective December 1,
10.15	Credit Facility between GulfWest Energy Inc. and Highbridge/Zwirn Special Opportunities Fund, L.P., and Drawbridge Special Opportunities Fun
#10.16	Employment Agreement between Tracy Price and GulfWest Energy Inc., dated April 1, 2005. (incorporated by reference to Exhibit 10.22 of the Co
#10.17	Employment Agreement between Tommy Atkins and GulfWest Energy Inc., dated April 1, 2005 (incorporated by reference to Exhibit 10.23 of the
#10.18	Employment Agreement between Jay S. Mengle and GulfWest Energy Inc., dated April 1, 2005 (incorporated by reference to Exhibit 10.24 of the
#10.20	Summary terms of June 2005 Director Compensation Plan (incorporated by reference to page 47 of the Prospectus to our Post-Effective Amendme
10.21	Credit Agreement, dated July 15, 2005, among Crimson Exploration Inc., Wells Fargo, N.A., as agent and a lender, and each lender from time to ti
#10.22	Form of director and officer restricted stock grant (incorporated by reference to Exhibit 10.3 to our Form 8-K, Reg. No. 001-12108, filed with the C
10.23	First Amendment to Credit Agreement, dated as of March 6, 2006, among Crimson Exploration, Inc., Crimson Exploration Operating, Inc., LTW P
10.25	Second Amendment to Credit Agreement, dated as of August 31, 2006, among Crimson Exploration Inc., Crimson Exploration Operating, Inc., LT
10.26	Subordinate Credit Agreement, dated as of August 31, 2006, among Crimson Exploration Inc., Wells Fargo Energy Capital, Inc., as agent and a len

ITEM 15. Exhibits and Financial Statement Schedules. (continued)

22.1 Subsidiaries of the Registrant (included on page 2) of this Annual Report.

*23.1 Consent of Grant Thornton LLP

25 Power of Attorney (included on signature page of this Annual Report).

*31.1 Certification of Chief Executive Officer pursuant to Exchange Rule 13a-15(e) as adopted pursuant to Section 302 of the Sarbanes-Oxley Act of 2002

*31.2 Certification of Chief Financial Officer pursuant to Exchange Rule 13a-15(e) as adopted pursuant to Section 302 of the Sarbanes-Oxley Act of 2002

*32.1 Certification of Chief Executive Officer pursuant to 18.U.S.C Section 1350 pursuant to Section 906 of the Sarbanes-Oxley Act of 2002; filed herewi

*32.2 Certification of Chief Financial Officer pursuant to 18.U.S.C Section 1350 pursuant to Section 906 of the Sarbanes-Oxley Act of 2002; filed herewit

* filed herewith

management contract or compensatory plan or arrangement

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) 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.

CRIMSON EXPLORATION INC.

Date: April 2, 2007

By /s/ Allan D. Keel
Allan D. Keel, President

POWER OF ATTORNEY

Know all men by these presents, that each person whose signature appears below constitutes and appoints Allan D. Keel as his true and lawful attorney-in-fact and agent, with full power of substitution, for him and in his name, place, and stead, in any and all capacities to sign any and all amendments or supplements to this Annual Report on Form 10-K, and to file the same, and with all exhibits thereto and other documents in connection therewith, with the Securities and Exchange Commission, granting unto said attorney-in-fact and agent full power and authority to do and perform each and every act and thing requisite and necessary to be done as fully to all intents and purposes as he might or could do in person, hereby ratifying and confirming all that said attorney-in-fact and agent or his substitute or substitutes, may lawfully do or cause to be done by virtue hereof.

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/ Allan D. Keel	President, Chief Executive Officer	
Allan D. Keel	and Director	April 2, 2007
/s/ E. Joseph Grady	Senior Vice President and	
E. Joseph Grady	Chief Financial Officer	April 2, 2007
/s/ Richard L. Creel	Vice President Finance and	
Richard L. Creel	Chief Accounting Officer	April 2, 2007
/s/ Skardon F. Baker		
Skardon F. Baker	Director	April 2, 2007
/s/B. James Ford		
B. James Ford	Director	April 2, 2007
/s/ Lon Mc Cain		
Lon Mc Cain	Director	April 2, 2007
/s/ Lee B. Backsen		
Lee B. Backsen	Director	April 2, 2007

CRIMSON EXPLORATION INC.

FINANCIAL REPORT

DECEMBER 31, 2006

CONTENTS

All other Financial Statement Schedules have been omitted because they are either inapplicable or the information required is included in the financial statements or the notes thereto.

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and

Stockholders of Crimson Exploration Inc.

We have audited the accompanying consolidated balance sheets of Crimson Exploration Inc. and subsidiaries as of December 31, 2006 and 2005, and the related consolidated statements of operations, stockholders equity, and cash flows for each of the three years in the period ended December 31, 2006. These financial statements are the responsibility of the Company s management. Our responsibility is to express an opinion on these financial statements 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. The Company is not required to have, nor were we engaged to perform, an audit of its internal control over financial reporting. Our audit included consideration of internal control over financial reporting as a basis for designing audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the Company s internal control over financial reporting. Accordingly, we express no such opinion. An audit also includes 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, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, the consolidated financial statements referred to above present fairly, in all material respects, the financial position of Crimson Exploration Inc. 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.

As discussed in Note 1 to the consolidated financial statements, effective January 1, 2006, the Company adopted the provisions of Statement of Financial Accounting Standards No. 123 (revised 2004), *Share-Based Payments.*

Houston, Texas

March 30, 2007

CRIMSON EXPLORATION INC. AND SUBSIDIARIES
CONSOLIDATED BALANCE SHEETS

ASSETS

	December 31, 2006	2005
CURRENT ASSETS		
Cash and cash equivalents	$23,321	$474,393
Accounts receivable trade, net of allowance for doubtful accounts of $118,110 and $30,674 , respectively	3,283,270	3,498,488
Prepaid expenses	225,304	249,424
Derivative instruments	700,088	
Deferred tax asset, net		1,602,773
Total current assets	4,231,983	5,825,078
PROPERTY AND EQUIPMENT		
Oil and gas properties, using the successful efforts method of accounting	91,656,534	65,598,691
Other property and equipment	1,713,911	1,560,464
Less accumulated depreciation, depletion and amortization	(16,823,553)	(12,936,096)
Total property and equipment, net	76,546,892	54,223,059
NONCURRENT ASSETS		
Deposits	49,502	49,502
Investments		225,689
Debt issuance cost, net	449,583	274,214
Derivative instruments	2,233,800	
Deferred tax asset, net	1,190,962	2,517,407
Total other assets	3,923,847	3,066,812
TOTAL ASSETS	$84,702,722	$63,114,949

The Notes to Consolidated Financial Statements are an integral part of these statements.

CRIMSON EXPLORATION INC. AND SUBSIDIARIES
CONSOLIDATED BALANCE SHEETS

LIABILITIES AND STOCKHOLDERS EQUITY

	December 31, 2006	2005
CURRENT LIABILITIES		
Notes payable	$	$ 40,300
Current portion of long-term debt	91,093	80,883
Accounts payable trade	9,778,359	4,107,441
Accrued expenses	736,406	487,453
Income taxes payable	75	31,075
Asset retirement obligations	185,414	
Derivative instruments		2,108,583
Deferred tax liability, net	140,808	
Total current liabilities	10,932,155	6,855,735
NONCURRENT LIABILITIES		
Long-term debt, net of current portion	8,414,993	1,103,232
Asset retirement obligations	4,029,791	1,311,133
Derivative instruments		1,039,587
Total noncurrent liabilities	12,444,784	3,453,952
Total liabilities	23,376,939	10,309,687
COMMITMENTS AND CONTINGENCIES		
STOCKHOLDERS EQUITY		
Preferred stock (see Note 6)	1,032	1,033
Common stock (see Note 6)	3,334	2,899
Additional paid-in capital	79,693,736	72,877,718
Retained deficit	(18,372,319)	(20,076,388)
Total stockholders equity	61,325,783	52,805,262
TOTAL LIABILITIES AND STOCKHOLDERS EQUITY	$ 84,702,722	$ 63,114,949

The Notes to Consolidated Financial Statements are an integral part of these statements.

CRIMSON EXPLORATION INC. AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF OPERATIONS

	For the Years Ended December 31, 2006	2005	2004
OPERATING REVENUES			
Oil and gas sales	$ 21,477,735	$ 17,551,650	$ 11,101,114
Operating overhead and other income	181,746	131,158	106,559
Total operating revenues	21,659,481	17,682,808	11,207,673
OPERATING EXPENSES			
Lease operating expenses	7,527,589	5,585,297	4,879,754
Exploration expenses	443,496	395,327	
Depreciation, depletion and amortization	3,951,645	3,130,647	2,184,815
Dry holes, abandoned property and impaired assets	3,217,979	4,062,592	452,516
Asset retirement obligations	245,327	59,850	114,027
General and administrative	8,729,674	3,772,771	2,018,746
Loss on sale of assets	2,456	38,501	2,034,079
Total operating expenses	24,118,166	17,044,985	11,683,937
INCOME (LOSS) FROM OPERATIONS	(2,458,685)	637,823	(476,264)
OTHER INCOME AND EXPENSE			
Interest expense	(108,961)	(1,302,894)	(4,153,578)
Other financing costs	(228,320)	(1,955,501)	(1,472,318)
Loss from equity in investments	(1,843)	(71,679)	
Unrealized gain (loss) on derivative instruments	6,082,058	(1,642,643)	(1,505,527)
Forgiveness of debt			12,475,612
Total other income and (expense)	5,742,934	(4,972,717)	5,344,189
INCOME (LOSS) BEFORE INCOME TAXES	3,284,249	(4,334,894)	4,867,925
INCOME TAX (EXPENSE) BENEFIT	(1,425,305)	791,655	3,204,296
NET INCOME (LOSS)	1,858,944	(3,543,239)	8,072,221
DIVIDENDS ON PREFERRED STOCK (PAID 2006-$154,875; 2005-$1,127,643; 2004-$0)	(3,648,925)	(3,562,472)	(455,612)
NET INCOME (LOSS) AVAILABLE TO COMMON SHAREHOLDERS	$ (1,789,981)	$ (7,105,711)	$ 7,616,609
NET INCOME (LOSS) PER SHARE			
BASIC	$ (0.55)	$ (2.66)	$ 4.11
DILUTED	$ (0.55)	$ (2.66)	$ 2.41
WEIGHTED AVERAGE SHARES OUTSTANDING			
BASIC	3,231,000	2,673,882	1,853,502
DILUTED	3,231,000	2,673,882	3,161,828

The Notes to Consolidated Financial Statements are an integral part of these statements.

CRIMSON EXPLORATION INC. AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF STOCKHOLDERS' EQUITY
FOR THE YEARS ENDED DECEMBER 31, 2006, 2005 AND 2004

	NUMBER OF SHARES				ADDITIONAL	
	PREFERRED STOCK	COMMON STOCK	PREFERRED STOCK	COMMON STOCK	PAID-IN CAPITAL	RETAINED DEFICIT
BALANCE, DECEMBER 31, 2003	19,000	1,849,365	$ 190	$ 1,850	$ 29,300,335	$ (23,477,727)
Issuance of warrants for additional financing					916,029	
Issuance of preferred stock related to current refinancing	8,000		80		3,863,665	
Conversion of preferred stock to common stock	(1,710)	90,143	(17)	90	(73)	
Current year net income						8,072,221
BALANCE, DECEMBER 31, 2004	25,290	1,939,508	253	1,940	34,079,956	(15,405,506)
Common stock issued for services and fees		6,319		6	53,273	
Preferred stock issued:						
Series A	2,000		20		1,499,980	
Series G	81,000		810		36,686,311	
Preferred stock conversions:						
Series A to common	(3,250)	464,286	(33)	464	(431)	
Series F to common	(340)	17,000	(3)	17	(14)	
Series H to common	(1,450)	207,143	(14)	207	(193)	
Common stock dividends paid:						
Series A preferred		35,625		36	331,278	
Series H preferred		12,973		13	114,975	
Options and warrants exercised		216,323		216	112,583	
Current year net loss						(3,543,239)
Dividends paid on preferred stock						(1,127,643)
BALANCE, DECEMBER 31, 2005	103,250	2,899,177	1,033	2,899	72,877,718	(20,076,388)
Share based compensation		28,644		29	3,876,986	
Stock options exercised		10,700		11	48,139	
Preferred H converted	(30)	4,287	(1)	4	(4)	
Acquisition of oil and gas leases		369,789		370	2,736,043	
Current year net income						1,858,944
Dividends paid on Preferred H		21,000		21	154,854	(154,875)
BALANCE, DECEMBER 31, 2006	103,220	3,333,597	$ 1,032	$ 3,334	$ 79,693,736	$ (18,372,319)

The Notes to Consolidated Financial Statements are an integral part of these statements.

CRIMSON EXPLORATION INC. AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF CASH FLOWS

	For the Years ended December 31,		
	2006	2005	2004
CASH FLOWS FROM OPERATING ACTIVITIES:			
Net income (loss)	$ 1,858,944	$ (3,543,239)	$ 8,072,221
Adjustments to reconcile net income (loss) to net cash provided by operating activities:			
Depreciation, depletion and amortization	3,951,645	3,130,647	2,184,815
Dry holes, abandoned property, impaired assets	3,209,943	3,698,633	452,516
Asset retirement obligations	69,694	59,850	46,478
Stock compensation expense	3,819,600	44,164	
Debt issuance cost	134,131	1,829,046	1,379,818
Discount on note payable		502,120	413,910
Forgiveness of debt			(12,475,612)
Deferred tax expense (benefit)	1,425,305	(797,629)	(3,322,551)
Notes payable issued for interest expense			61,046
Loss on sale of assets	2,456	38,501	2,034,079
Loss from equity in investments	1,843	71,679	
Unrealized (gain) loss on derivative instruments	(6,082,058)	1,642,643	1,505,527
Provision for bad debts	87,436	30,674	
Changes in operating assets and liabilities:			
Increase in accounts receivable trade, net	(161,811)	(1,997,038)	(267,271)
(Increase) decrease in prepaid expenses	24,120	(120,707)	30,552
Increase (decrease) in accounts payable and accrued expenses	5,946,284	(1,045,249)	398,114
Net cash provided by operating activities	14,287,532	3,544,095	513,642
CASH FLOWS FROM INVESTING ACTIVITIES:			
Deposits		(39,698)	10,338
Proceeds from sale of property and equipment	7,950	101,905	1,250,675
Capital expenditures	(21,777,332)	(10,797,961)	(6,141,988)
Net cash used in investing activities	(21,769,382)	(10,735,754)	(4,880,975)
CASH FLOWS FROM FINANCING ACTIVITIES:			
Proceeds from sale of preferred stock, net		38,187,121	3,363,745
Proceeds from common stock options and warrants exercised	48,150	56,450	
Payments on debt	(18,805,206)	(34,258,132)	(18,144,776)
Proceeds from debt issuance	26,097,334	4,274,241	21,304,258
Debt issuance cost	(309,500)	(323,664)	(2,228,135)
Dividends paid		(681,341)	
Net cash provided by financing activities	7,030,778	7,254,675	4,295,092
INCREASE (DECREASE) IN CASH AND CASH EQUIVALENTS	(451,072)	63,016	(72,241)
CASH AND CASH EQUIVALENTS, Beginning of year	474,393	411,377	483,618
CASH AND CASH EQUIVALENTS, End of year	$ 23,321	$ 474,393	$ 411,377
CASH PAID FOR INTEREST	$ 291,163	$ 2,000,218	$ 3,718,940
CASH PAID FOR INCOME TAXES	$ 31,000	$ 93,154	$

The Notes to Consolidated Financial Statements are an integral part of these statements.

CRIMSON EXPLORATION INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

1. Organization and Summary of Significant Accounting Policies

The following is a summary of the significant accounting policies consistently applied by management in the preparation of the accompanying consolidated financial statements.

Organization

On June 29, 2005, our predecessor, GulfWest Energy Inc., a Texas corporation (GulfWest), merged with and into Crimson Exploration Inc., a Delaware corporation (Crimson), for the purpose of changing our state of incorporation from Texas to Delaware (the Reincorporation). The Reincorporation was accomplished pursuant to an Agreement and Plan of Merger, dated June 28, 2005, which was approved by GulfWest s shareholders at the 2005 Annual Shareholders Meeting held June 1, 2005.

On January 5, 2006 we formed Crimson Exploration Operating, Inc., a Delaware corporation, as our wholly owned subsidiary through which all oil and gas operations will be conducted. Effective March 2, 2006, we merged all our subsidiaries, with the exception of LTW Pipeline Co., into this newly formed corporation. LTW Pipeline Co. remains an inactive subsidiary of Crimson Exploration Inc.

On September 15, 2006, we effected a reverse stock split where each ten shares of outstanding common stock were exchanged for one new share of common stock. All periods presented have been adjusted to reflect the effects of the reverse stock split.

Cash and Cash Equivalents

We consider all highly liquid investment instruments purchased with remaining maturities of three months or less to be cash equivalents for purposes of the consolidated statements of cash flows and other statements. We maintain cash on deposit in non-interest bearing accounts, which, at times, exceed federally insured limits. We have not experienced any losses on such accounts and believe we are not exposed to any significant credit risk on cash and equivalents.

Non-cash Investing and Financing Activities

During the twelve month period ended December 31, 2006 we issued 323,565 shares of common stock, valued at approximately $2.4 million, as partial consideration for the acquisition of oil and gas leases via merger with Core Natural Resources, Inc. As a result of this transaction we also increased the book value of oil and gas leases by recording a $1.6 million deferred tax liability related to the difference in the fair market value of the assets acquired and their underlying tax basis. Related to this transaction, we also acquired a 2% overriding royalty interest in that leasehold acreage by issuing 46,224 shares of common stock valued at $0.3 million. In a separate transaction, we recorded an increase in oil and gas leases of $0.5 million through the exchange of a $0.3 million account receivable and through the reclassification of a $0.2 million investment in a partnership upon distribution of assets by that partnership. We also paid dividends to the holders of Series H Preferred Stock by issuing 21,000 shares of common stock valued at $0.2 million based on the closing market price on the date of the grants. Also accrued compensation of $3,315 was converted to additional paid in capital when 1,400 options, accounted for under variable accounting rules, were exercised. In addition, we financed new field trucks for $29,844.

On February 28, 2006, we also issued 26,234 restricted shares of our common stock to members of our management in lieu of cash bonuses. The stock vested on February 28, 2007. We expensed $163,960 during the year ended December 31, 2006, and will expense $32,790 over the remaining vesting period. In addition, on May 12, 2006 we issued 2,410 restricted shares of our common to our directors as compensation. The stock vests on May 12, 2007. We expensed $12,742 during the year ended December 31, 2006 and will expense $7,258 over the remaining vesting period.

During the twelve month period ended December 31, 2005, we settled $0.4 million in dividends by issuing 4,860 shares of common stock and we issued 2,910 shares of common stock to satisfy a $23,280 fee for a loan extension prior to the sale of the Series G Preferred Stock. In addition we recorded $29,999 in director fee expense associated with the issuance of 3,409 shares of restricted common stock to directors under the new Director Compensation Plan. Also, accrued compensation of $56,350 was converted to additional paid in capital when 8,750 options, accounted for under variable option accounting rules, were exercised. During 2005, we also invested $23,006 in an oil and gas partnership by contributing our cost basis in undrilled oil and gas leases and acquired $0.1 million in oil and gas properties in exchange of an account receivable. In addition, we financed new field trucks for $45,724.

Use of Estimates in the Preparation of Financial Statements

The preparation of consolidated financial statements in conformity with generally accepted accounting principles requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the date of the consolidated financial statements and the reported amounts of revenues and expenses during the reporting period. Actual results could differ from those estimates.

Oil and Gas Properties

We use the successful efforts method of accounting for oil and gas producing activities. Costs to acquire mineral interests in oil and gas properties, to drill and equip exploratory wells that find proved reserves, and to drill and equip development wells are capitalized. Costs to drill exploratory wells that do not find proved reserves, delay rentals and geological and geophysical costs are expensed (except those costs used to determine a drill site location).

As we acquire significant oil and gas properties, any unproved property that is considered individually significant is periodically assessed for impairment of value, and a loss is recognized at the time of impairment by providing an impairment allowance. Capitalized costs of producing oil and gas properties and support equipment, after considering estimated dismantlement and abandonment costs and estimated salvage values, are depreciated and depleted by the unit-of-production method.

On the sale of an entire interest in an unproved property, gain or loss on the sale is recognized, taking into consideration the amount of any recorded impairment if the property has been assessed individually. If a partial interest in an unproved property is sold, the amount received is treated as a reduction of the cost of the interest retained. On the sale of an entire or partial interest in a proved property, gain or loss is recognized, based upon the fair values of the interests sold and retained.

Asset Retirement Obligations

In 2003, we adopted the Statement of Financial Accounting Standards No. 143, Asset Retirement Obligations (SFAS 143) which requires us to recognize an estimated liability for the plugging and abandonment of our oil and gas wells and associated pipelines and equipment. The liability and the associated increase in the related long-lived asset are recorded in the period in which our asset retirement obligation (ARO) is incurred. The liability is accreted to its present value each period and the capitalized cost is depreciated over the useful life of the related asset.

The estimated liability is based on historical experience in plugging and abandoning wells, estimated remaining lives of those wells based on reserves estimates and federal and state regulatory requirements. The liability is discounted using an assumed credit-adjusted risk-free rate.

Revisions to the liability could occur due to changes in estimates of plugging and abandonment costs, changes in the risk-free rate or remaining lives of the wells, or if federal or state regulators enact new plugging and abandonment requirements. At the time of abandonment, we recognize a gain or loss on abandonment to the extent that actual costs do not equal the estimated costs.

At the end of 2006, we increased our ARO to include the new wells drilled in our Madisonville-Rodessa project. At the same time, the original cost assumptions for existing fields were reevaluated due to certain fields having wells plugged and abandoned in 2006 which caused losses to be incurred as the actual costs were higher than the original estimated costs. It was determined at that time that the costs associated with abandonment have

increased significantly due to higher service costs prevalent in the industry, and the timing of settling the obligations was also revised. For further details, see the reconciliation of our asset retirement obligation liability in Note 3.

Other Property and Equipment

The following tables set forth certain information with respect to our other property and equipment. Other property and equipment is recorded at cost and we provide for depreciation and amortization using the straight-line method over the following estimated useful lives of the respective assets:

Assets	Years
Automobiles	3-5
Office equipment	7
Computer software	7
Gathering system	10
Well servicing equipment	10

Capitalized costs relating to other properties and equipment:

	2006	**2005**
Automobiles	$328,265	$ 367,882
Office equipment	226,456	196,189
Computer software	243,077	129,150
Gathering system	271,651	271,651
Well servicing equipment	$644,462	$ 595,592
	1,713,911	1,560,464
Less accumulated depreciation	(1,096,851)	(966,449)
Net capitalized cost	$617,060	$ 594,015

Impairments

We have adopted SFAS 144 Accounting for the Impairment or Disposal of Long- Lived Assets . Accordingly, impairments, measured using fair market value, are recognized whenever events or changes in circumstances indicate that the carrying amount of long-lived assets (other than unproved oil and gas properties discussed above) may not be recoverable and the future undiscounted cash flows attributable to the asset are less than its carrying value.

Revenue Recognition

The Company follows the sales (takes or cash) method of accounting for oil and gas revenues. Under this method, we recognize revenues on production as it is taken and delivered to its purchasers. The volumes sold may be more or less than the volumes we are entitled to base our ownership interest in the property. These differences result in a condition known in the industry as a production imbalance. Our crude oil and natural gas imbalances are not significant.

Trade Accounts Receivable

We grant credit to creditworthy independent and major oil and gas companies for the sale of crude oil and natural gas. In addition, we grant credit to joint owners of oil and gas properties, which we operate through our subsidiaries. Such amounts are secured by the underlying ownership interests in the properties.

Trade accounts receivable are reported in the consolidated balance sheets at the outstanding principal adjusted for any charge offs. An allocation for doubtful accounts is recognized by management based upon a review of specific customer balances, historical losses and general economic conditions.

Fair Value of Financial Instruments

At December 31, 2006 and 2005, our financial instruments consist of accounts receivable, notes payable and long-term debt. Interest rates currently available to us for notes payable and long-term debt with similar terms and remaining maturities are used to estimate fair value of such financial instruments. Accordingly, since interest rates on substantially all of our debt are variable, market based rates, the carrying amounts are a reasonable estimate of fair value.

Debt Issuance Costs

Debt issuance costs incurred are capitalized and subsequently amortized over the term of the related debt on a straight-line basis.

Earnings (Loss) Per Share

We have adopted Statement of Financial Accounting Standards (SFAS) No. 128 Earnings Per Share , which requires that both basic earnings (loss) per share and diluted earnings (loss) per share be presented on the face of the statement of operations. Basic earnings (loss) per share are based on the weighted-average number of outstanding common shares. Diluted earnings (loss) per-share is based on the weighted-average number of outstanding common shares and the effect of all potentially diluted common shares.

Stock Based Compensation

In December 2004, the Financial Accounting Standards Board (FASB) issued Statement of Financial Accounting Standards (SFAS) No. 123 (revised 2004) Share-Based Payment (SFAS No. 123R), which replaces SFAS No. 123, Accounting for Stock-Based Compensation and supersedes APB Opinion 25. SFAS No. 123R requires all share-based payments to employees, including grants of employee stock options, to be recognized in the financial statements based on the fair values beginning with the first interim period in fiscal year 2006. The pro forma disclosures previously permitted under SFAS No. 123 are no longer an alternative to financial statement recognition.

We adopted SFAS No. 123R on January 1, 2006 using the modified prospective method in which compensation cost is recognized beginning with the effective date based on the requirements of: (a) SFAS No. 123R for all share-based payments granted after January 1, 2006; and (b) SFAS No. 123 for all awards granted to employees prior to January 1, 2006 that remain unvested on January 1, 2006. Under our 2005 Stock Incentive Plan we had approximately 2.2 million unvested options outstanding at January 1, 2006 with authorization to issue an additional 460,000 under that plan. It is our policy to issue new shares for any options exercised. We use the Black-Scholes option pricing model to measure the fair value of stock options. For the unvested options, the previously measured but unrecognized compensation expense, based on the fair value at the original grant date, will be recognized in our financial statements over the remaining vesting period. Prior to the adoption of SFAS No. 123R, we followed the intrinsic value method in accordance with APB 25 to account for employee stock-based compensation. Prior period financial statements have not been restated.

The modified prospective method requires us to estimate forfeitures in calculating the expense related to stock-based compensation as opposed to recognizing forfeitures as they occur. All of our unvested options are held by our executive officers and new employees. One of our executive officers forfeited his unvested options during 2006 upon his resignation from the company. This was not anticipated as we had no prior history of an executive officer forfeiting options. We do not anticipate that there will be any further forfeitures of unvested options by our executive officers or new employees.

The following table illustrates the effect on net income after tax and net income per common share as if we had applied the fair value recognition provisions of SFAS No. 123 to stock-based compensation for the periods shown below:

	For the Years Ende December 31, 2005	200
ncome, as reported	$(7,105,711)	$7,616,
Total stock-based employee compensation expense included in reported net income, net of related tax effect		129,
ct: Total stock-based employee compensation expense determined under fair value based method for all awards, net of related tax effect	(2,008,123)	(425,
orma net income	$(9,113,834)	$7,320,
ings per share:		
eported:		
c	$ (2.66)	$ 4
ed	$ (2.66)	$ 2
orma:		
c	$ (3.41)	$ 3
ed	$ (3.41)	$ 2
ghted-average fair value per share of options granted	$ 14.24	$ 4

Recent Accounting Pronouncements

In September 2006, the Securities and Exchange Commission staff (SEC) issued SAB 108. SAB 108 was issued to provide consistency to how companies quantify financial statement misstatements. SAB 108 establishes an approach that requires companies to quantify misstatements in financial statements based on effects of the misstatement on both the consolidated balance sheet and statement of operations and the related financial statement disclosures. Additionally, companies must evaluate the cumulative effect of errors existing in prior years that previously had been considered immaterial. We adopted SAB 108 in connection with the preparation of our annual financial statements for the year ended December 31, 2006 and found no adjustments necessary.

In September 2006, the FASB issued SFAS No. 157, *Fair Value Measurements* (SFAS No. 157). SFAS No. 157 defines fair value, establishes a framework for measuring fair value in generally accepted accounting principles and expands disclosures about fair value measurements. SFAS No. 157 does not require any new fair value measurements, rather, its application will be made pursuant to other accounting pronouncements that require or permit fair value measurements. SFAS No.157 is effective for financial statements issued for fiscal years beginning after November 15, 2007, and interim periods within those years. The provisions of SFAS No. 157 are to be applied prospectively upon adoption, except for limited specified exceptions. We are evaluating the requirements of SFAS No. 157 and do not expect the adoption to have a material impact on our Consolidated Balance Sheet or Statement of Operations.

In June 2006, the Financial Accounting Standards Board (FASB) issued Interpretation No. 48, Accounting for Uncertainty in Income Taxes-an interpretation of FASB Statement No. 109 (FIN 48). FIN 48 clarifies the accounting for uncertainty in income taxes recognized in a company s financial statements in accordance with FASB Statement No. 109, Accounting for Income Taxes. It prescribes a recognition threshold and measurement attribute for the financial statement recognition and measurement of a tax position taken or expected to be taken in a tax return. FIN 48 also provides guidance on derecognition, classification, interest and penalties, accounting in interim periods, disclosure and transition. FIN 48 is effective for fiscal years beginning after December 15, 2006 and will be adopted by us on January 1, 2007. We have not been able to complete our evaluation of the impact of adopting FIN 48 and as a result, are not able to estimate the effect the adoption will have on our financial position and results of operations, including our ability to comply with current debt covenants.

Texas House Bill 3 (HB3), which was signed into law in May, 2006, provides a comprehensive change in the method of business taxation in Texas. HB3 eliminates the taxable capital and earned surplus components of the existing Texas franchise tax and replaces these components with a taxable margin tax. This change is effective for tax reports filed on or after January 1, 2008 (which are based upon 2007 business activity) and results in no impact on our current Texas income tax. We are required to include, in income, the impact of HB3 on deferred state income taxes during the period which includes the date of enactment. Based upon the available information regarding the proposed implementation of this new tax, we have determined that no significant change in the amount of net deferred state income taxes is needed.

2. Recapitalization

On April 27, 2004, we completed an $18.0 million financing package with new energy lenders. We used $15.7 million in net proceeds from the financing to retire existing debt of $27.6 million, resulting in forgiveness of debt of $12.5 million, the elimination of a hedging liability and the return to the Company of Series F Preferred Stock with an aggregate liquidation preference of $1.0 million (this preferred stock, at the request of the Company, was transferred by the previous lender to a financial advisor to the Company and to two affiliated companies). The taxable gain resulting from these transactions was completely offset by available net operating loss carryforwards for income tax purposes. The term of the note was eighteen months and it bore interest at the prime rate plus 11%. The rate increased by 0.75% per month beginning in month ten. We paid the new lenders $1.2 million in cash fees and also issued them warrants to purchase 2,035,621 shares of our common stock at an exercise price of $0.01 per share, expiring in five years (exercised in April, 2005). The warrants were subject to anti-dilution provisions. In connection with the February 2005 transactions described below, the anti-dilution provisions were amended such that additional issuances of stock (other than issuances to all holders) would not trigger an adjustment to the number of shares issuable upon exercise of the warrants.

On January 7, 2005, we amended our April 2004 credit agreement to extend the target date for repayment to February 28, 2005. We exercised this option on January 26, 2005 and issued 29,100 shares of our common stock in connection with this amendment.

On February 28, 2005, we sold in a private placement, 81,000 shares of our Series G Preferred Stock to OCM GW Holdings, LLC (OCMGW) for an aggregate offering price of $40.5 million. GulfWest Oil and Gas Company (GWOG), a subsidiary of the Company, issued, in a private placement, 2,000 shares of our Series A Preferred Stock, having a liquidation preference of $1.0 million, to OCMGW for $1.5 million. Net proceeds of the offerings of approximately $38.2 million after expenses were used for the repayment of substantially all of our outstanding debt and other past due liabilities and for general corporate purposes.

The Series G Preferred Stock bears a coupon of 8% per year, has an aggregate liquidation preference of $40.5 million (excluding accumulated undeclared dividends), is convertible into common stock at $9.00 per share and is senior to all of our capital stock. For the first four years after issuance, we may defer the payment of dividends on the Series G Preferred Stock and these deferred dividends will also be convertible into our common stock at $9.00 per share. In addition, the Series G Preferred Stock is entitled to nominate and elect a majority of the members of our Board of Directors.

In connection with these recapitalization transactions, the terms of the Series A Preferred Stock were amended such that by March 15, 2005, all such stock would either convert into a newly created Series H Preferred Stock on a one for one basis or into common stock at a conversion price of $3.50 per share. The Series H Preferred Stock is required to be paid a dividend of 40 shares of common stock per share of Series H Preferred Stock per year. The outstanding Series H Preferred Stock has an aggregate liquidation preference of $2.6 million. The Series H Preferred Stock is senior to all of our capital stock other than Series G Preferred Stock (See Note 6 Stockholders Equity).

In addition, we amended the terms of our 9,000 shares of Series E Preferred Stock such that the coupon of 6% per year may be deferred for the next four years and these deferred dividends will be convertible into common stock at conversion price of $9.00 per share. The original liquidation preference of the Series E Preferred Stock of $500 per share remains convertible into common stock at $20.00 per share. The Series E Preferred Stock has an aggregate liquidation preference of $4.5 million (excluding accumulated undeclared dividends), and is senior to all of our common stock, of equal preference with our Series D Preferred Stock as to liquidation and junior to our Series G and Series H Preferred Stock.

On May 17, 2005, we executed a promissory note for the benefit of OCMGW, in the principal amount of $1.0 million, payable on the earlier of July 17, 2005 or the day on which we are able to make draws under a credit facility under which greater than $1.0 million may be borrowed. Interest on the unpaid principal accrued at 4.59% per annum. We repaid the note in full on July 19, 2005 from borrowings under our new $100.0 million senior secured revolving credit facility.

On July 15, 2005, we entered into a $100.0 million senior secured revolving credit facility with Wells Fargo Bank, National Association (Senior Credit Agreement). Borrowings under the credit facility are subject to a borrowing base limitation based on our current proved oil and gas reserves. The original borrowing base was set at $20.0 million and is subject to semi-annual redeterminations. The facility is secured by a lien on all our assets, and the assets of our subsidiaries, as well as a security interest in the stock of all our subsidiaries. The credit facility had an original term of three years, and all principal amounts, together with all accrued and unpaid interest, were due and payable in full on June 30, 2008. Proceeds from extensions of credit under the facility will be for acquisitions of oil and gas properties and for general corporate purposes. The facility also provides for the issuance of letters-of-credit up to a $3.0 million sub-limit. We incurred $0.3 million in issuance costs associated with the credit facility which are being amortized over its life. In connection with the Subordinate Credit Agreement discussed below, we amended our Senior Credit Agreement, primarily to provide for the Subordinate Credit Agreement but also to provide for a redetermined borrowing base of $25.0 million and to extend the maturity date of the facility to August 31, 2009.

Advances under the facility will be in the form of either base rate loans or Eurodollar loans. The interest rate on the base rate loans fluctuates based upon the higher of (1) the lender s prime rate and (2) the Federal Funds rate, plus a margin of 0.50%, plus an additional margin of between 0.0% and 0.5% depending on the percent of the borrowing base utilized at the time of the credit extension. The interest rate on the Eurodollar loans fluctuates based upon the rate at which Eurodollar deposits in the London Interbank market (Libor) are quoted for the maturity selected, plus a margin of 1.25% to 2.00% depending on the percent of the borrowing base utilized at the time of the credit extension. Eurodollar loans of one, three and nine months may be selected by us. A commitment fee of 0.375% on the unused portion of the borrowing base will accrue, and be payable quarterly in arrears.

Effective August 31, 2006, we entered into a $150 million subordinate credit facility with Wells Fargo Energy Capital, Inc. (the Subordinate Credit Agreement). Initial availability under the Subordinate Credit Agreement is $15.0 million. No borrowings under the Subordinate Credit Agreement were made at closing, nor were any outstanding at December 31, 2006.

The facility will be secured on a subordinated basis by a lien on all the assets of the Company and its subsidiaries, as well as a security interest in the stock of all the Company s subsidiaries. The obligations under the Subordinate Credit Agreement will be subordinate and junior to those under the Senior Credit Agreement.

The Subordinate Credit Agreement has a term of three-and-a-half years, and all principal amounts, together with all accrued and unpaid interest, will be due and payable in full on February 28, 2010. Proceeds from extensions of credit under the facility will be for acquisitions of oil and gas properties and for general corporate purposes.

Advances under the Subordinate Credit Agreement will be in the form of either base rate loans or Eurodollar loans. The interest rate on the base rate loans fluctuates based upon the higher of (1) the lender s prime rate and (2) the Federal Funds rate, plus a margin of 0.50%, plus an additional margin of 3.75%. The interest rate on the Eurodollar loans fluctuates based upon the rate at which Eurodollar deposits in the London Interbank market (Libor) are quoted for the maturity selected, plus a margin of 5.25%. Eurodollar loans of one, three and six months may be selected by the Company. A commitment fee of 0.50% on the unused portion of the borrowing base will accrue, and be payable quarterly in arrears. Repayments made during the first twelve months of the term Subordinate Credit Agreement will be subject to a 1% prepayment penalty. Once repaid, amounts under the Subordinate may not be re-borrowed.

Under the Subordinate Credit Agreement, borrowings are at our discretion. However, once the Company s outstanding balance under the Senior Credit Agreement reaches $10.0 million, the Company s next $10.0 million in borrowings must be funded under the Subordinate Credit Agreement.

The credit agreement includes usual and customary affirmative covenants for credit facilities of this type and size, as well as customary negative covenants, including, among others, limitation on liens, hedging, mergers, asset sales or dispositions, payments of dividends, incurrence of additional indebtedness, certain leases and investments outside of the ordinary course of business. At December 31, 2006 we were in compliance with the aforementioned covenants.

3. Asset Retirement Obligations

A reconciliation of our asset retirement obligation liability is as follows:

	December 31, 2006	2005
Balance beginning of year	$ 1,311,133	$ 1,144,854
Accretion expense	83,807	77,634
Liabilities incurred	283,388	65,852
Liability settled	(32,049)	
Revisions	2,568,926	22,793
Balance end of year	$ 4,215,205	$ 1,311,133

4. Accrued Expenses

Accrued expenses consisted of the following:

	December 31, 2006	2005
Accrued compensation	$ 531,662	$ 340,450
Loan fees and interest	148,106	72,003
Taxes	38,430	
Professional fees	18,208	75,000
	$ 736,406	$ 487,453

5. Notes Payable and Long-Term Debt

Notes payable are as follows:

Non-interest bearing note payable to an unrelated party; payable out of 50% of the net transportation revenues from a certain natural gas pipeline that is no

Total Notes Payable

The weighted average interest rate for notes payable at December 31, 2005 was 0.00%.

Long-term debt is as follows:

Subordinated promissory notes to various unlocatable individuals	
Notes payable to finance vehicles, payable in aggregate monthly installments of approximately $3,600, including interest of 5.99% to 10.49% at Decembe	
Line of credit (up to $25.0 million) to a bank due August 2009; secured by all of our assets; interest at the higher of prime or Federal Fund rate plus a marg	
Less current portion	
Total long-term debt	

Estimated annual maturities for long-term debt are as follows:

2007	$	91,093
2008		32,029
2009		8,379,931
2010		3,033
2011		
	$	8,506,086

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6. **Stockholders Equity**

Common Stock

Par value $0.001; 200,000,000 shares authorized; 3,333,597 and 2,899,177 shares issued and outstanding as of December 31, 2006 and 2005, respectively

Preferred Stock

Series D, par value $0.01; 12,000 shares authorized; 8,000 shares issued and outstanding at December 31, 2006 and 2005. The Series D preferred stock do

Series E, par value $0.01; 9,000 shares authorized; 9,000 shares issued and outstanding at December 31, 2006 and 2005. The Series E pays dividends, as d

Series G, par value $0.01; 81,000 shares authorized; 81,000 issued and outstanding at December 31, 2006 and December 31, 2005. The Series G preferred

Series H, par value $0.01; 6,500 shares authorized; 5,220 and 5,250 shares issued and outstanding at December 31, 2006 and 2005, respectively. The Serie

All classes of preferred shareholders have a liquidation preference over common shareholders of $500 per preferred share, plus accrued dividends. Accumulated, unpaid and undeclared dividends at December 31, 2006 were $6,497,096 (Series E $497,096; Series G $5,965,150; Series H $34,850). Once dividends are declared, they may be converted to 1,396 shares of common stock (Series E 50; Series G 1,326; Series H 20).

Stock Options

We maintained a 1994 Stock Option and Compensation Plan (the 1994 Plan), which terminated on February 11, 2004. There are options to purchase 24,500 shares of Common Stock still outstanding and exercisable under the 1994 Plan. Effective July 15, 2004, we implemented our 2004 Stock Option and Compensation Plan (the 2004 Plan). There are options to purchase 126,300 shares of Common Stock outstanding and exercisable under the 2004 Plan. Effective February 28, 2005 we implemented our 2005 Stock Incentive Plan (2005 Plan) and there were options to purchase approximately 2.2 million shares of Common Stock outstanding under the 2005 Plan. Options to purchase 471,800 shares of Common Stock were exercisable at December 31, 2006, at exercise prices ranging from $4.50 to $18.10.

Following is a schedule by year and by exercise price of the expiration of our stock options outstanding as of December 31, 2006:

	2007	**2008**	**2009**	**2010**	**Thereafter**	**Total**
$4.50		77,300	20,500	18,500		116,300
$6.60					7,000	7,000
$6.65					1,000	1,000
$7.50	3,500	25,000				28,500
$7.60					4,000	4,000
$7.80					200	200
$9.70					360,000	360,000
$11.60					173,300	173,300
$12.50					556,740	556,740
$17.00					1,088,760	1,088,760
$18.10		6,000				6,000
	3,500	108,300	20,500	18,500	2,191,000	2,341,800

Pursuant to SFAS 123R for options issued under our 2005 plan, we recorded $3.7 million in expense (included in general and administrative expense on the Statement of Operations) for the year ended December 31, 2006, and estimate $10.5 million will be expensed over the remaining vesting period. We assumed a weighted average risk free interest rate of 4.04%, weighted average expected life of 7.8 years, weighted average expected volatility of 92.33% and no expected dividends.

The following table summarizes stock option activity for the three years ended December 31, 2006:

	Number of Share Underlying Options	Weighted Average Exercise Price
Outstanding at December 31, 2003	110,200	$ 9.00
Granted	161,000	4.80
Exercised	(76,300)	(8.00)
Expired		
Outstanding at December 31, 2004	194,900	6.00
Granted	2,240,000	14.24
Exercised	(23,900)	(8.20)
Expired		
Outstanding at December 31, 2005	2,411,000	13.60
Granted	51,000	13.12
Exercised	(10,700)	(4.50)
Expired	(6,500)	(8.30)
Forfeited	(103,000)	(14.89)
Outstanding at December 31, 2006	2,341,800	$ 13.62
Exercisable at December 31, 2006	471,800	$ 11.45

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The following table summarizes information about stock options outstanding at December 31, 2006:

Exercise Prices	Number Outstanding	Weighted Average Remaining Life (Years)	Number Exercisable
$ 4.50	116,300	2.1	116,300
$ 6.60	7,000	9.9	
$ 6.65	1,000	9.9	
$ 7.50	28,500	1.4	28,500
$ 7.60	4,000	9.5	
$ 7.80	200	9.7	
$ 9.70	360,000	8.2	54,000
$ 11.60	173,300	8.3	25,995
$ 12.50	556,740	8.2	81,000
$ 17.00	1,088,760	8.2	160,005
$ 18.10	6,000	1.3	6,000
	2,341,800	7.8	471,800

The following table reflects the impact of adopting SFAS No. 123R for the year ended:

	December 31, 2006
Compensation expense related to stock options, net of tax of $1,404,859	$ 2,292,138
Basic earnings per share impact	$ (0.71)
Diluted earnings per share impact	$ (0.38)

On February 28, 2006, we also issued 26,234 restricted shares of our common stock to members of our management in lieu of cash bonuses. The stock vested on February 28, 2007. We expensed $163,960 during the year ended December 31, 2006, and will expense $32,790 over the remaining vesting period. In addition, on May 12, 2006 we issued 2,410 restricted shares of our common to our directors as compensation. The stock vests on May 12, 2007. We expensed $12,742 during the year ended December 31, 2006 and will expense $7,258 over the remaining vesting period.

Stock Warrants

We have issued a significant number of stock warrants for a variety of reasons, including compensation to employees, additional inducements to purchase our common or preferred stock, inducements related to the issuance of debt and for payment of goods and services. Following is a schedule by year of the activity related to stock warrants, including weighted-average exercise prices of warrants in each category:

	2006 Wtd Avg Prices	Number	**2005** Wtd Avg Prices	Number	**2004** Wtd Avg Prices	Number
Balance, January 1	$ 7.40	147,000	$ 3.80	400,062	$ 7.60	196,500
Warrants issued	$		$ 0.10	5,000	$ 0.10	203,562
Warrants exercised or expired	$ 7.50	(144,000)	$ (1.70)	(258,062)	$	
Balance, December 31	$ 0.10	3,000	$ 7.40	147,000	$ 3.80	400,062

Following is a schedule by year and by exercise price of the expiration of our stock warrants outstanding as of December 31, 2006:

	Exercise Price	2007	2008	Total
$	0.10		3,000	3,000
	Total Warrants		3,000	3,000

7. Income (Loss) Per Common Share

The following is a reconciliation of the numerators and denominators used in computing income (loss) per share:

	2006	2005	2004
Net income (loss)	$ 1,858,944	$ (3,543,239)	$ 8,072,221
Preferred stock dividends	(3,648,925)	(3,562,472)	(455,612)
Income (loss) available to common shareholders	$ (1,789,981)	$ (7,105,711)	$ 7,616,609
Weighted-average number of shares of Common Stock basic (denominator)	3,231,000	2,673,882	1,853,502
Income (loss) per share - basic	$ (0.55)	$ (2.66)	$ 4.11
Weighted average number of shares of Common Stock diluted (denominator)	3,231,000	2,673,882	3,161,828
Income (loss) per share diluted	$ (0.55)	$ (2.66)	$ 2.41

The numerator for basic earning per share is income (loss) available to common shareholders. The numerator for diluted earnings per share is net income in 2004 and net loss available to common shareholders in 2006 and 2005, due to antidilution.

Potential dilutive securities (vested stock options, vested stock warrants and convertible preferred stock) in 2006 and 2005 have not been considered since we reported a net loss and, accordingly, their effects would be antidilutive. The potentially dilutive shares would have been 5,581,202 shares and 5,606,198 shares in 2006 and 2005 respectively.

8. Related Party Transactions

As described in Our Company Financial Recapitalization OCM GW Holdings purchased 81,000 shares of Series G Preferred Stock and 2,000 shares of Series A Preferred Stock for $42.0 million. Skardon F. Baker, a director, is an employee of and B. James Ford, also a director is a managing director of Oaktree Capital Management, LLC, the ultimate parent of OCM GW Holdings.

On May 17, 2005, we executed a promissory note for the benefit of OCM GW Holdings, in the principal amount of $1.0 million, payable on the earlier of July 17, 2005 or the day on which we are able to make draws under a credit facility under which greater than $1.0 million may be borrowed. Interest on the unpaid principal accrued at 4.59% per annum. We repaid the note in full on July 19, 2005 from borrowings under our new $100.0 million senior secured revolving credit facility.

In connection with our April 2004 financing, J. Virgil Waggoner, a former director, and Star-Tex Trading Co., an entity managed by John Loehr, an officer at the time and a former director, purchased 3,000 shares and 200 shares, respectively, of Series A Preferred Stock at a price of $500 per share. Both Mr. Waggoner and Star-Tex, in connection with the February 2005 offering, elected to exchange those shares for an equal number of shares of Series H Preferred Stock.

On October 23, 1995, we sold $25,000 each of 9% promissory notes in a private offering to two trusts, the trustee of whom is John E. Loehr, an officer at the time of the transaction and currently a director. The balance of the notes plus accrued interest thereon at February 28, 2005 was $87,855. The note was paid off in connection with the February 2005 offering.

In June, 1999, we issued a promissory note with interest at 8.5% to Mr. Marshall A. Smith III, an officer and director at the time, in the amount of $124,083 for accrued compensation. At February 28, 2005, the note had a balance and accrued and unpaid interest of $99,360 and was being paid in monthly installments of approximately $1,500 per month. The note was paid off in connection with the February 2005 offering.

On November 6, 2002, Mr. J. Virgil Waggoner, a former director, provided us a loan in the initial amount of $1.2 million, which was subsequently increased to a total of $1.5 million which was outstanding at February 28, 2005. We issued Mr. Waggoner a promissory note with interest at the prime rate (prime rate 4.0% at May 26, 2004), secured by common stock of our wholly-owned subsidiary, DutchWest Oil Company. Mr. Waggoner also received warrants to purchase 625,000 shares of our common stock at an exercise price of $0.75 per share. The note with accrued interest was paid off in connection with the February 2005 offering, for a total payment amount of approximately $1.7 million.

On April 26, 2001, we obtained a line of credit of up to $2.5 million from a bank for which two directors, Mr. J. Virgil Waggoner and Mr. Marshall A. Smith, were guarantors. On April 3, 2002, the balance of the line of credit was retired and a new line of credit of up to $3.0 million was obtained from the bank for which Mr. Waggoner and Mr. Smith were guarantors. The line of credit was paid off in connection with the February 2005 offering.

On March 5, 2004, we entered into an Option Agreement for the Purchase of Oil and Gas Leases (the *Addison Agreement*) with W. L. Addison Investments L.L.C., a private company owned by Mr. J. Virgil Waggoner and Mr. John E. Loehr, two of our directors (*Addison*). Under the Addison Agreement, Addison agreed to pay Summit, on our behalf, the non-recouped and outstanding advanced funds amounting to $1.2 million, thereby retiring the Summit Agreement except for certain surviving obligations with respect to areas of mutual interest and lease bank agreements. Under the Summit Agreement, Summit loaned the company $0.6 million for the workover of selected wells and Summit funded $0.6 million for leasing in the Iola field of east Texas. In return Summit earned an 8.5% working interest in the workover wells and retained a 25% working interest in the Iola leases and drilling program. For consideration of such payment, Addison acquired certain oil and gas leases and well bores from Summit but agreed to grant us a 180-day redemption option (which was extended by mutual consent) to purchase the same for $1.2 million, plus interest at the prime rate plus 2%. We tendered Addison a promissory note in the amount of $0.6 million, with interest at the prime rate plus 2%, to substitute for an account payable to Summit, pursuant to the Summit Agreement, in the same amount. The note would be considered paid in full if we exercised the redemption option and paid the $1.2 million, plus interest. Summit retained the right to participate up to a 25% working interest in the drilling of any wells on the leases acquired by Addison. In the event we exercised the redemption option, Addison could have, at its sole option, retained up to a 25% working interest in the leases. The Addison Agreement was extended on July 15, 2004. We exercised the redemption option and Addison received approximately $1.3 million at the closing of the February 2005 offering and waived its rights under the agreement to a working interest under the leases.

As part of the April 2004 refinancing, the former lender agreed to return all 2,000 shares of our Series F Preferred Stock held by it. Rather than receive the shares as treasury shares (which would have meant cancellation of the series) at our request the former lender transferred 400 of the shares to ST Advisory Corp., an entity owned by John Loehr, our former CEO and a current director, 400 of the shares to a financial advisor to the Company, and 200 of the shares to Thomas R. Kaetzer, our President and Director at that time and 1,000 shares to Intermarket Management LLC, an entity partially owned by M. Scott Manolis, one of our directors at that time. These transfers were to compensate the financial advisor and Mr. Loehr, Kaetzer and Manolis for service to the Company. On September 29, 2004, the financial advisor with 400 shares transferred 140 shares to three non-management transferees.

Approximately $0.7 million of the proceeds from the February 2005 offering was used to pay accrued and unpaid dividends on the preferred stock. J. Virgil Waggoner received $0.5 million as a result. On December 22, 2004, ST Advisory Corp, Intermarket Management LLC and Mr. Kaetzer converted their Series F preferred shares into common stock. At the closing of the February 2005 offering they were paid their proportionate share of accrued dividends due on the 2000 shares, which totaled $17,167.

As part of the closing of the February 2005 offering, the investor and the Company agreed to pay certain legal, accounting and other due diligence costs and, also certain closing fees which totaled approximately $3.75 million. Of this amount certain related parties received the following fees: OCM GW $1.0 million; Intermarket Management LLC $0.5 million; Mr. Allan D. Keel $0.3 million (which was used to invest in the subject offering).

In January 2005, Allan D. Keel, our current president and chief executive officer, and another individual lent an aggregate of $0.2 million to the Company, which was repaid in full out of the proceeds of the February 2005 offering. Approximately $0.1 million of that loan was attributable to Mr. Keel. In addition, Mr. Keel received warrants to purchase 30,000 shares of Common Stock at $0.01 share in connection with this transaction.

9. Income Taxes

Income tax expense/(benefit) for 2006, 2005 and 2004 consist of the following:

		2006		**2005**			**2004**	
Current tax	$		$	5,974		$	128,255	
Deferred tax expense (benefit)		1,425,305		(797,629	)		(3,332,551	)
Income tax expense (benefit)	$	1,425,305	$	(791,655	)	$	(3,204,296	)

The following table summarizes changes in our deferred tax asset obtained by applying a tax rate of 38% to the income (loss) before income taxes for the year ended December 31, 2006, 2005 and 2004.

		2006			**2005**			**2004**	
Tax expense (benefit) calculated at statutory rate	$	1,248,015		$	(1,647,259	)	$	1,849,812	
Increase (reductions) in taxes due to:									
Income tax credits					(5,974	)		(118,255	)
Effect on non-deductible expenses		(14,339	)		223,918			170,530	
Change in valuation allowance					582,809			(4,693,201	)
Other		191,629			48,877			(531,437	)
Deferred tax expense (benefit)	$	1,425,305		$	(797,629	)	$	(3,332,551	)

As of December 31, 2006 we had net operating loss carryforwards of approximately $24.4 million, which are available to reduce future taxable income and the related income tax liability. We expect we will not be able to utilize carryforwards of approximately $9.1 million due to the limitations of Internal Revenue Code Section 382. The net operating loss carryforward expires at various dates through 2026.

The components of the net deferred federal income tax assets (liabilities) recognized in our consolidated balance sheets are as follows:

	December 31, 2006	2005
Deferred tax assets		
Net operating loss carryforwards	$ 8,755,256	$ 4,249,890
Income tax credits	117,695	124,229
Oil and gas properties		1,530,416
Derivative instruments		1,196,304
Deferred compensation	1,473,526	87,400
Other	403,627	11,656
Deferred tax assets before valuation allowance	10,750,104	7,199,895
Valuation Allowance	(3,079,715)	(3,079,715)
Net deferred tax assets	7,670,389	4,120,180
Deferred tax liabilities		
Oil and gas properties	(5,683,039)	
Derivative instruments	(937,196)	
Deferred tax liabilities	(6,620,235)	
Net deferred tax assets	$ 1,050,154	$ 4,120,180

Our deferred taxes decreased by approximately $3.0 million during 2006. In addition to a decrease of $1.4 million from 2006 tax expense, we recorded a reduction of $1.6 million related to our Core acquisition. Deferred tax assets are shown net of a $3.1 million valuation allowance. The valuation allowance was recorded because we expect we will not be able to use net operating loss carryforwards utilization of approximately $9.1 million due to the limitations of Internal Revenue Code Section 382.

10. Oil and Gas Hedging Activities

In the past we have entered into, and may in the future enter into, certain derivative arrangements with respect to portions of our oil and natural gas production to reduce our sensitivity to volatile commodity prices. During 2005 and 2004, we entered into price swaps and put agreements with financial institutions. We believe that these derivative arrangements, although not free of risk, allow us to achieve a more predictable cash flow and to reduce exposure to price fluctuations. However, derivative arrangements limit the benefit to us of increases in the prices of crude oil and natural gas sales. Moreover, our derivative arrangements apply only to a portion of our production and provide only partial price protection against declines in price. Such arrangements may expose us to risk of financial loss in certain circumstances. We expect that the monthly volume of derivative arrangements will vary from time to time. We continuously reevaluate our price hedging program in light of increases in production, market conditions, commodity price forecasts, capital spending and debt service requirements.

The following derivatives were in place at December 31, 2006.

Crude Oil			**Volume/ Month**	**Price/ Unit**		**Fair Value**
Jan 2007	Dec 2007	Collar	3,000 Bbls	Floor $45.00-$59.45 Ceiling	$	(263,241)
Jan 2007	Dec 2007	Collar	5,100 Bbls	Floor $69.64-$84.35 Ceiling		405,118
Jan 2008	Dec 2008	Swap	6,500,Bbls	$76.40		642,372
Jan 2009	Dec 2009	Swap	5,200 Bbls	$74.20		389,732
Jan 2010	Dec 2010	Swap	4,250 Bbls	$72.32		253,578
Jan 2011	Dec 2011	Swap	3,300 Bbls	$70.74		157,211
Natural Gas						
Jan 2007	Dec 2007	Collar	20,000 MMBTU	Floor $6.00-$6.95 Ceiling		(69,458)
Jan 2007	Dec 2007	Collar	37,000 MMBTU	Floor $8.00-$11.84 Ceiling		628,440
Jan 2008	Dec 2008	Swap	47,000 MMBTU	$8.97		475,933
Jan 2009	Dec 2009	Swap	36,000 MMBTU	$8.32		182,434
Jan 2010	Dec 2010	Swap	29,000 MMBTU	$7.88		131,769
Total fair value asset						2,933,888
Current portion						(700,088)
Noncurrent portion					$	2,233,800

We also had the following put options in place at December 31, 2006, for the months reflected.

Crude Oil		**Monthly Volume**	**Price per Bbl**
Nov 2006	Apr 2007	5,000 Bbls	$25.75

The value of these put options was minimal.

At the end of each reporting period we are required by SFAS 133 Accounting for Derivative Instruments and Hedging Activities, to record on our balance sheet the mark-to-market valuation of our derivative instruments. We recorded a net asset for derivative instruments at December 31, 2006 of $2.9 million and a net liability of $3.1 million at December 31, 2005. As a result of these agreements, we recorded a non-cash increase in earnings, for unsettled contracts, of $6.1 million, a non-cash charge of $1.6 million and a non-cash charge of $1.5 million for the twelve month periods ended December 31, 2006, 2005 and 2004, respectively. The estimated change in fair value of the derivatives is reported in Other Income and Expense as unrealized (gain) loss on derivative instruments.

For settled contracts, we realized losses, reflected as reductions in oil and gas revenues, of $0.8 million, $3.9 million and $1.8 million for the twelve month periods ended December 31, 2006, 2005 and 2004, respectively.

11. Commitments and Contingencies

Lease Obligations

In October 2006, we entered into a sublease agreement for new office space under an eighty-two (82) month lease that commences on April 1, 2007. The lease expires January 2014.

We currently lease office space at one location under a sixty-four (64) month lease, which commenced December 1, 2001 and was amended May 30, 2002, after expansion. The lease expires March 2007. Total rent expense for the years ended December 31, 2006, 2005 and 2004, were approximately $184,161, $153,000 and $142,500, respectively.

Litigation

From time to time, we are involved in litigation arising out of our operations or from disputes with vendors in the normal course of business. As of March 19, 2007, we are not currently engaged in any legal proceedings that are expected, individually or in the aggregate, to have a material effect on our consolidated financial statements.

Employment Agreement

Effective February 28, 2005, we entered into employment agreements with our President/Chief Executive Officer and Senior Vice President /Chief Financial Officer. Each agreement has a term of three years with automatic yearly extensions unless we or the officer elects not to extend the agreement. These agreements provide for a base salary of $240,000 per year and $220,000, respectively. If the contracts are terminated by us without cause or by the employee for good reason, and the employee has been in compliance with employee contract terms, the employee may receive a cash payment equal to the greater of two times current year base salary plus prior year bonus, or $600,000, and health insurance benefits for two years in the future.

Effective April 1, 2005, we entered into employment agreements with our four other Senior Vice Presidents. However, one of our Senior Vice Presidents resigned in 2006. Each agreement has a term of two years with automatic yearly extensions unless we or the officer elects not to extend the agreement. These agreements provide for a base salary ranging from $180,000 to $185,000. If the contracts are terminated by us without cause or by the employee for good reason, and the employee has been in compliance with the employee contract terms, the employee is entitled to receive a cash payment equal to the greater of two-times current year base salary plus prior year bonus, or $500,000, and health insurance benefits for two years in the future.

12. Oil and Gas Properties (Unaudited)

The following tables set forth certain information with respect to our oil and gas producing activities (all within the United States) for the periods presented:

Capitalized Costs Relating to Oil and Gas Producing Activities:

	2006	2005
Unproved oil and gas properties	$ 8,031,565	$ 1,326,341
Proved oil and gas properties	75,262,705	59,614,594
Support equipment and facilities	8,362,264	4,657,756
	91,656,534	65,598,691
Less accumulated depreciation, depletion and amortization	(15,726,702)	(11,969,647)
Net capitalized costs	$ 75,929,832	$ 53,629,044

Results of Operations for Oil and Gas Producing Activities:

	2006	2005	2004
Oil and gas sales	$ 21,477,735	$ 17,551,650	$ 11,101,114
Production costs	(7,527,589)	(5,585,297)	(4,879,754)
Exploration expenses	(443,496)	(395,327)	
Depreciation, depletion and amortization	(3,748,377)	(2,971,050)	(1,954,256)
Dry holes, abandoned property and impaired assets	(3,217,979)	(4,062,592)	(452,516)
Asset retirement obligation	(245,327)	(59,850)	(114,027)
Income tax expense			
Results of operations for oil and gas producing activities - income	$ 6,294,967	$ 4,477,534	$ 3,700,561

The following table sets forth the composition of dry holes, abandoned property and impaired assets:

	2006	2005[1]	2004
Dry holes	$	$ 3,519,644	$
Abandoned property	67,999	10,552	390,522
Impaired assets	3,149,980	532,396	61,994
	$ 3,217,979	$ 4,062,592	$ 452,516

(1) Mustang Island has been reclassified from an impairment to a dry hole.

Costs Incurred in Oil and Gas Producing Activities:

	2006	2005	2004
Property Acquisitions			
Proved	$	$ 142,867	$ 6,742
Unproved	8,745,363	1,244,975	17,347
Development Costs	6,465,719	6,171,241	6,117,899
Exploration Costs	10,783,663	3,157,841	
	$ 25,994,745	$ 10,716,924	$ 6,141,988

The following table shows oil and gas property dispositions:

	2006	2005	2004
Oil and gas properties	$	$ 31,337	$ 5,425,040
Accumulated depreciation, depletion and amortization			(1,659,001)
Net oil and gas properties	$	$ 31,337	$ 3,766,039

As a result of these sales we recorded a loss on sale of $13,022 and $2.0 million in 2005 and 2004, respectively.

Oil and Gas Reserves Information

The estimates of proved oil and gas reserves utilized in the preparation of the financial statements are estimated in accordance with guidelines established by the Securities and Exchange Commission and the Financial Accounting Standards Board, which require that reserve estimates be prepared under existing economic and operating conditions with no provision for price and cost escalations over prices and costs existing at year end except by contractual arrangements.

We emphasize that reserve estimates are inherently imprecise. Accordingly, the estimates are expected to change as more current information becomes available. Our policy is to amortize capitalized oil and gas costs on the unit of production method, based upon these reserve estimates. It is reasonably possible that, because of changes in market conditions or the inherent imprecision of these reserve estimates, that the estimates of future cash inflows, future gross revenues, the amount of oil and gas reserves, the remaining estimated lives of the oil and gas properties, or any combination of the above may be increased or reduced in the near term. If reduced, the carrying amount of capitalized oil and gas properties may be reduced materially in the near term.

The following unaudited table sets forth proved oil and gas reserves, all within the United States, at December 31, 2006, 2005, and 2004, together with the changes therein.

	Crude Oil *(BBls)*	Natural Gas *(Mcf)*
QUANTITIES OF PROVED RESERVES:		
Balance December 31, 2003	5,037,963	32,660,119
Revisions	(426,932)	(2,857,240)
Extensions, discoveries and additions	-	2,823,427
Purchase	-	-
Sales	(1,474,115)	(2,502,596)
Production	(173,865)	(1,033,433)
Balance December 31, 2004	2,963,051	29,090,277
Revisions	(78,648)	(3,025,395)
Extensions, discoveries and additions	-	-
Purchase	953	67,631
Sales		-
Production	(177,833)	(1,482,250)
Balance December 31, 2005	2,707,523	24,650,263
Revisions	(21,823)	882,566
Extensions, discoveries and additions		7,397,142
Purchase		
Sales		
Production	(184,881)	(1,542,423)
Balance December 31, 2006	2,500,819	31,387,548
PROVED DEVELOPED RESERVES:		
December 31, 2004	2,575,403	20,965,574
December 31, 2005	2,423,196	19,658,165
December 31, 2006	2,249,424	27,145,360

Standardized measure of discounted future net cash flows relating to proved reserves:

	2006	**2005**	**2004**
Future cash inflows	$ 313,312,927	$ $425,080,357	$ $290,998,312
Future production and development costs			
Production	108,693,762	101,677,305	80,880,330
Development	26,229,488	27,467,896	24,141,982
Future cash flows before income taxes	178,389,677	295,935,156	185,976,000
Future income taxes	(43,534,046)	(91,664,228)	(49,871,272)
Future net cash flows after income taxes	134,855,631	204,270,928	136,104,728
10% annual discount for estimated timing of cash flows	(57,442,604)	(85,873,789)	(52,602,351)
Standardized measure of discounted future net cash flows	$ 77,413,027	$ $118,397,139	$ 83,502,377

The following reconciles the change in the standardized measure of discounted future net cash flows:

	2006	2005	2004
Beginning of year	$ 118,397,139	$ 83,502,377	$ 88,327,420
Changes from:			
Purchases of proved reserves		230,291	-
Sales of producing properties			(13,756,990)
Extensions, discoveries and improved recovery, less related costs	12,096,684		10,280,787
Sales of oil and gas produced, net of production costs	(13,950,146)	(11,966,353)	(6,221,360)
Revision of quantity estimates	1,980,452	(16,437,404)	(12,614,337)
Accretion of discount	17,156,239	11,415,713	11,439,568
Change in income taxes	28,176,711	(22,544,291)	(4,552,701)
Changes in estimated future development costs	(946,764)	(6,461,166)	(8,040,393)
Development costs incurred that reduced future development costs	6,465,719	6,171,241	6,117,899
Change in sales and transfer prices, net of production costs	(75,110,065)	88,819,225	8,245,446
Changes in production rates (timing) and other	(16,852,942)	(14,332,494)	4,277,038
End of year	$ 77,413,027	$ 118,397,139	$ 83,502,377

The calculations used to produce the figures in this table are based on current cost and price factors at December 31 for each year. The average sales prices utilized in the estimation of our proved reserves were $57.67 per Bbl and $5.40 per Mcf, $57.79 per Bbl and $10.90 per Mcf, $40.41 per Bbl and $5.89 per Mcf, at December 31, 2006, 2005 and 2004, respectively.

13. **Quarterly Results (Unaudited)**

Summary data relating to the results of operations for each quarter for the years ended December 31, 2006 and 2005 follows:

	Three Months Ended			
	March 31	June 30	September 30	December 31
2006				
Net sales	$ 5,139,649	$ 5,180,193	$ 5,636,179	$ 5,703,460
Income (loss) from operations	1,048,133	333,436	(15,370)	(3,824,884)
Net income (loss) available to common shareholders	476,231	(713,830)	1,690,997	(3,243,379)
Income(loss)per common share				
Basic	$ 0.16	$ (0.22)	$ 0.51	$ (0.97)
Diluted	$ 0.16	$ (0.22)	$ 0.29	$ (0.97)
Weighted average shares outstanding				
Basic	2,958,039	3,309,651	3,317,720	3,328,925
Diluted	8,554,496	3,309,651	8,889,438	3,328,925
2005				
Net sales	$ 3,664,333	$ 4,393,040	$ 4,736,297	$ 4,889,138
Income (loss) from operations	968,147	849,565	1,381,323	(2,522,711)
Net income (loss) available to common shareholders	(3,547,445)	(79,362)	(2,188,922)	(1,289,982)
Income(loss)per common share				
Basic and Diluted	$ (1.71)	$ (0.03)	$ (0.76)	$ (0.45)
Weighted average shares outstanding				
Basic and Diluted	2,070,662	2,860,502	2,887,366	2,896,953

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REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and

Stockholders of Crimson Exploration Inc.

We have audited in accordance with the standards of the Public Accounting Oversight Board (United States) the consolidated financial statements of Crimson Exploration Inc. and subsidiaries referred to in our report dated March 30, 2007, which is included in this Form 10-K. Our audit was conducted for the purpose of forming an opinion on the basic financial statements taken as a whole. Schedule II is presented for purposes of additional analysis and is not a required part of the basic financial statements. The information for the years ended December 31, 2004, 2005 and 2006 included in Schedule II has been subjected to the auditing procedures applied in the audit of the basic financial statements and, in our opinion, is fairly stated in all material respects in relation to the basic financial statements taken as a whole.

Houston, Texas

March 30, 2007

CRIMSON EXPLORATION INC. AND SUBSIDIARIES

SCHEDULE II VALUATION AND QUALIFYING ACCOUNTS

FOR THE YEARS ENDED DECEMBER 31, 2006, 2005 AND 2004

DECRIPTION	BALANCE AT BEGINNING OF PERIOD	PROVISIONS/ ADDITIONS	RECOVERIES/ DEDUCTIO
For the year ended December 31, 2004:			
Valuation allowance for deferred tax assets	$7,190,107	$	$(4,693,201
For the year ended December 31, 2005			
Accounts receivable	$	$30,674	$
Valuation allowance for deferred tax assets	$2,496,906	$582,809	$
For the year ended December 31, 2006:			
Accounts receivable	$30,674	$87,436	$
Valuation allowance for deferred tax assets	$3,079,715	$	$