UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
WASHINGTON, D.C. 20549

FORM 10-K/A

Amendment No. 1

☒ ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
For the fiscal year ended December 31, 2007
OR
☐ 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	**20-3037840**
(State or other jurisdiction of incorporation or organization)	(I.R.S. Employer Identification No.)
717 Texas Avenue, Suite 2900 **Houston, Texas 77002**	**77002**
(Address of principal executive offices)	(Zip Code)

(713) 236-7400
(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 ☐ No ☒

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 ☐ No ☒

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 ☒ No ☐

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

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

Large accelerated filer ☐ Accelerated filer ☐ Non-accelerated filer ☐ Smaller reporting company ☒
(Do not check if smaller reporting company)

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

As of June 30, 2007, the aggregate market value of the registrant's common stock held by non-affiliates of the registrant was $16,944,751 based on the closing sales price of $7.25 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 20, 2008, there were 5,162,758 shares of common stock outstanding.

DOCUMENTS INCORPORATED BY REFERENCE

Portions of our Definitive Proxy Statement for the 2008 Annual Meeting, expected to be filed within 120 days of our fiscal year end, are incorporated by reference into Part III.

EXPLANATORY NOTE

We are filing this Amendment No. 1 on Form 10-K/A to the Crimson Exploration Inc. Annual Report on Form 10-K for the year ended December 31, 2007 in response to comments received by us from the Commission's Staff pursuant to its review of our Form 10-K for the fiscal year ended December 31, 2007. Pursuant to the Commission's comments, we have amended our 2007 Form 10-K to document the name of our independent petroleum engineers (PART I – ITEM 2) and to add a total column to the Consolidated Statements of Stockholders' Equity. In addition, we have added language to clarify the accounting treatment of a change in accounting estimate related to the calculation of preferred stock dividends (PART II – ITEM 5 and ITEM 7).

The following items are included in this amendment:

PART I – ITEM 2. Properties
Significant Properties

PART II – ITEM 5. Market for Registrant's Common Equity and Related Stockholder Matters
Preferred Stock

PART II – ITEM 7. Management's Discussion and Analysis of Financial Condition and Results of Operations
Results of Operations
Year Ended December 31, 2007 Compared to Year Ended December 31, 2006
Dividends on Preferred Stock

Consolidated Statements of Stockholders' Equity

In addition, this amendment includes the following exhibits:

Exhibit 23.1 – Consent of Grant Thornton LLP

Exhibit 23.2 – Consent of Netherland, Sewell & Associates, Inc.

Exhibit 31.1 - Certification of Chief Executive Officer pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.

Exhibit 31.2 - Certification of Chief Financial Officer pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.

Exhibit 32.1 - Certification of Chief Executive Officer pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.

Exhibit 32.1 - Certification of Chief Financial Officer pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.

All other information contained in the original Form 10-K remains unchanged. However, the entire report with all Items is included in this Form 10-K/A-1 for the convenience of the reader. This Amendment No.1 on Form 10-K/A does not reflect events occurring after the filing of our Annual Report on Form 10-K on March 31, 2008 or include, or otherwise modify or update, the disclosure contained therein in any way except as expressly indicated above.

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, 2007, our part of the estimated *proved reserves* these properties contained was approximately 2.9 million barrels (*MBbl*) of oil, 91.2 billion cubic feet (*Bcf*) of natural gas and 3.6 million barrels (*MBbl*) of natural gas liquids with an estimated *Net Present Value discounted* *at 10% (PV-10)* of $531.4 million. At present, substantially all of our properties are located on land in Texas, Louisiana, Colorado and Mississippi, except for certain properties in the shallow inland and offshore waters of 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.

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 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.

Prior to March 2, 2006 Crimson Exploration Inc. had six active and three inactive, direct or indirect, wholly owned subsidiaries. The active subsidiaries were GulfWest Oil and Gas Company, GulfWest Oil and Gas Company (Louisiana) LLC, SETEX Oil and Gas Company, RigWest Well Service, Inc., Dutch West Oil Company and GulfWest Development Company. On January 5, 2006 we formed Crimson Exploration Operating, Inc. ("*CEO*"), 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.

On May 8, 2007, CEO acquired certain oil and natural gas properties and related assets in the South Texas and Gulf Coast areas of Louisiana and Texas ("the *STGC Properties*") pursuant to a Membership Interest Purchase and Sale Agreement (the "*Purchase Agreement*") from EXCO Resources, Inc. ("*EXCO*") through the acquisition of 100% of the membership interest of Southern G Holdings, LLC ("*SGH*"). These properties were operated under SGH as a wholly owned subsidiary of CEO until SGH merged with CEO on December 31, 2007. The consolidated statements of operations include the results of operations of the STGC Properties from May to December 2007.

At December 31, 2007, our proved reserves were comprised of 13.4% crude oil, 70.1% natural gas and 16.5% natural gas liquids. 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.

Our principal office is currently located at 717 Texas Avenue, Suite 2900, Houston, Texas 77002 and our telephone number is (713) 236-7400.

Subsequent Event

Sale of Barnett Shale

We and one of our operator-partners entered into a series of agreements to sell our interests in wells and undeveloped acreage in the Fort Worth Barnett Shale Play in Johnson and Tarrant counties, Texas to another industry participant active in that area. We owned a 12.5% non-operating working interest in the assets being sold. Closing on the transaction is expected to occur in two stages, the first of which closed on February 29, 2008 and the second stage is expected to close on or around the end of the first quarter of 2008.

The final total consideration to be paid by the buyer will be based on existing wells and undeveloped acreage owned by us and our partner at the time of the closing. We and our partner will continue to drill wells and accumulate acreage until the time of the final closing. Our share of the estimated final consideration is projected to be between $28.0 and $32.0 million. The consideration received on February 29, 2008 for the first closing was approximately $22.2 million. Proceeds received on the first closing for our interest were used to repay amounts outstanding under our revolving credit facility, with no reduction in borrowing base on the revolver anticipated.

Highlights from 2007

For 2007, we produced an estimated 13.2 Bcfe of natural gas equivalents, or approximately 36,300 Mcfe per day, an approximate five-fold increase over the 2.7 Bcfe, or 7,300 Mcfe per day, produced in 2006. At year end 2007, we were producing approximately 52,000 Mcfe per day. The dramatic increase in production for the quarter and year is attributable to the South Texas and Gulf Coast producing assets acquired in May 2007 from EXCO.

During the fourth quarter 2007, we participated in four non-operated wells within the Lobo/Perdido Trend of South Texas, all in Zapata County, of which two were successful, giving us a 67% success rate on a total of nine wells drilled for the year in this area. Three of these wells were put on production at various times during the fourth quarter of 2007. In the fourth quarter, we also participated in the successful drilling of two non-operated wells in the Felicia area of Liberty County, Texas, a key field in the properties acquired from EXCO, giving us an 80% success rate on a total of five wells in the area for the year. Two of these wells were put on production at various times during the fourth quarter of 2007. We also continued to accumulate acreage and drill wells in the Fort Worth Barnett Shale Trend of Johnson County, Texas and participated in the successful drilling of three wells during the fourth quarter of 2007, giving us a 100% success rate on eight wells since we began drilling in June of 2007.

In May 2007, we acquired the STGC Properties from EXCO for total consideration, as of the January 1, 2007 effective date, of $285.0 million in cash and 750,000 shares of our common stock valued at approximately $4.6 million on the closing date. After reduction for applicable adjustments for the net results of operations between the effective date and the closing date, and other customary purchase price adjustments, the cash portion of the purchase price paid at closing was $245.4 million, after taking into account a post-closing adjustment. After considerations for typical closing adjustments, $229.0 million of the purchase price was allocated to proved properties and $28.6 million of the purchase price was allocated to unproved properties. The properties acquired include over 200 producing wells in over 30 fields, are 90% natural gas and are approximately 80% proved developed producing by value. We have an average 50% working interest in the properties and operate more than 80% of the value acquired. The cash portion of the purchase price was financed through an amended and restated $400.0 million revolving credit facility and a new $150.0 million second lien credit facility. The acquisition was accomplished by way of conveyance of 100% of the membership interests of SGH from EXCO to us.

Also, in May 2007, we relocated our corporate headquarters to expanded office space in downtown Houston, Texas.

Our Business Strategy

We pursue a balanced investment mix of acquisition, exploitation and exploration activities to create value for our shareholders. Our geographic focus area for these oil and gas related activities is the Gulf Coast region of the United States. Oil and gas activities, such as property acquisitions, leasing, exploration and development drilling, *workovers and recompletions,* are the principal activities we engage in.

The key elements of our business strategy are:

Acquisitions. To the extent financial resources are available, we pursue the acquisition of interests in crude oil and natural gas properties (i) being divested by larger independents or major oil companies, (ii) held by smaller, under-capitalized operators or (iii) through corporate transactions. Our 2007 acquisition of the STGC Properties generated an inventory of exploration and development capital projects that allow us to enhance the value of the producing properties acquired. Future acquisitions are also expected to create value through capital project inventory recognition and execution.

Exploitation. A second aspect of 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 infield and step-out drilling, *workovers*, *recompletions*, and more efficiently using production facilities. Currently, we operate approximately 76% of our current production base, and own an average approximate 55% working interest in our operated properties. This operating control enables us to manage the nature, timing and costs of developing and servicing such wells, and the timing and marketing of the resulting production.

Exploration. Prior to 2005, we did not drill exploratory wells due to limited capital and the cost and risk associated with oil and gas exploration. Since 2005, we have begun to incorporate exploration as a component of our growth strategy by hiring technical professionals, building our geological and seismic databases, and in 2007 we acquired certain *producing properties* from EXCO that included prospective acreage for oil and gas exploration. We also purchased 3-D seismic over a significant amount of the prospective acreage.

We have also developed an internal prospect generation capability to identify higher potential drilling opportunities, and have entered into exploration ventures with industry partners on a non-operated basis. In 2007, we also began acquiring seismic data to use in identifying exploration prospects. At this time, we have a library of approximately 3,200 square miles of 3D data and have commitments on 1,500 miles of 2D data. These data will be utilized for field exploitation and new exploration opportunities. We believe that exploration balances our acquisition and exploitation efforts with higher risk and higher reward opportunities. As such, we intend to allocate a meaningful amount toward the identification, high-grading, leasing, and drilling of exploratory oil and gas wells.

We believe generating and investing in high cash flow, high return opportunities in the Gulf Coast region is the best value-added strategy to pursue for our shareholders.

Our Employees

At March 20, 2008, we had 67 full time employees, of whom 20 were field personnel. None of our employees are covered by collective bargaining agreements. We believe our relationship with our employees is favorable.

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, 2007, 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.

Our substantial indebtedness could possibly have important consequences to our shareholders, including the following:

(i) 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;

(ii) We may be more highly leveraged than certain of our competitors, which may place us at a competitive disadvantage;

(iii) Certain of the borrowings under our debt agreements have floating rates of interest, which causes us to be vulnerable to increases in interest rates;

(iv) Our degree of leverage could make us more vulnerable to downturns in general economic conditions;

(v) Our ability to plan for, or react to, changes in our business and the industry in which we operate may be limited; and

(vi) Our ability to obtain additional financing on satisfactory terms to fund our working capital requirements, capital expenditures, investments, debt service requirements and other general corporate requirements may be reduced.

In addition, our senior secured first lien revolving credit facility and senior secured second lien term loan facility 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.

Our credit facilities 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 had outstanding debt of $235.8 million on our credit facilities at March 20, 2008. We may borrow up to an additional $114.2 million under our revolving 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 three 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.

We may not be able to successfully integrate the properties and assets we acquire with our existing operations.

Integration of the properties and assets we acquire may be a complex, time consuming and costly process. Failure to timely and successfully integrate these assets and properties with our operations may have a material adverse effect on our business, financial condition and result of operations. The difficulties of integrating these assets and properties present numerous risks, including:

- the acquisition may prove unprofitable and fail to generate anticipated cash flows;
- we may need to (i) recruit additional personnel and, in this highly competitive labor market, we cannot be certain that any of our recruiting efforts will succeed, and (ii) expand corporate infrastructure to facilitate the integration of our operations with those associated with the acquired properties, and failure to do so may lead to disruptions in our ongoing businesses or distract our management; and
- our management's attention may be diverted from other business concerns.

We are also exposed to risks that are commonly associated with acquisitions of this type, such as unanticipated liabilities and costs, some of which may be material. As a result, the anticipated benefits of acquiring assets and properties may not be fully realized, if at all.

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 25% of our total estimated *proved reserves* at December 31, 2007 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, 2007. The average sales prices of all properties were $89.92 per barrel of oil, $6.86 per thousand cubic feet (*Mcf*) of natural gas and $66.34 per barrel of natural gas liquids 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.

If we are unable to successfully address material weaknesses in our internal controls, our ability to report our financial results on a timely and accurate basis may be adversely affected. As a result, current and potential stockholders could lose confidence in our financial reporting and it may also result in regulatory sanctions or fines, which could have a material adverse effect on our business, operating results and stock price.

For the quarter ended March 31, 2007, our management concluded that we did not maintain effective controls over the preparation and review of the quarterly and annual tax provision and the related financial statement presentation and disclosure of income tax matters. Specifically, our historical documentation of related tax positions was not adequate to ensure the completeness and accuracy of FIN 48, *Accounting for Uncertainty in Income Taxes*, requirements for the quarter ended March 31, 2007, and could have resulted in a misstatement in the aforementioned tax accounts that could result in a material misstatement to the annual or interim financial statements that would not be prevented or detected. Accordingly, management concluded that this deficiency in internal control over financial reporting was a material weakness. Accordingly, in July 2007 we retained the services of a top tier tax accounting firm with expertise to assist us in the preparation of our disclosures and returns related to taxes. We have also identified and documented our key controls as they relate to taxes. Our President and Chief Executive Officer and our Chief Financial Officer were able to conclude based on their evaluation that our disclosure controls and procedures are effective.

Any failure to maintain the improvements in the controls over our financial reporting that we have currently put in place, could cause us to fail to meet our reporting obligations, to fail to produce reliable financial reports or to prevent fraud.

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 holds 2.0 million shares of common stock and has or has the right to acquire approximately 5.6 million shares of common stock pursuant to conversion of preferred stock held by it as follows:

(i) Series G Preferred Stock, including undeclared convertible dividends, and (ii) Series H Preferred Stock. Should OCMGW elect to convert its preferred stock, including accrued but unpaid dividends, together with the common stock currently held by it, OCMGW would hold approximately 63% of our outstanding common stock on a fully diluted basis, assuming conversion of all preferred stock and the exercise of all vested stock options of the Company, whether "in" or "out of" the money. 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 73% of the outstanding voting power on a fully diluted basis (assuming conversion of all preferred stock, and exercise all currently exercisable options, whether "in" or "out" of the money). 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 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 20, 2008 there were 5.2 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 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 granted employee stock options, is issued by us, the number of our outstanding shares of Common Stock would increase to approximately 10.7 million shares. Currently, we are authorized to issue 200.0 million shares of our Common Stock, 5.2 million shares of which are outstanding as of March 20, 2008. 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 common stock is thinly traded and there is no active trading market for our common stock and an active trading market may not develop.

Our common stock is not listed on any national or regional securities exchange. Quotations for shares of our common stock are listed by certain members of the National Association of Securities Dealers, Inc. on the OTC Electronic Bulletin Board. In recent years, the trading volume of our common stock has been very low and the transactions that have occurred were typically effected in transactions for which reliable market quotations have not been available. An active trading market may not develop or, if developed, may not continue for our equity securities, and a holder of any of these securities may find it difficult to dispose of, or to obtain accurate quotations as to the market value of such securities.

ITEM 2. Properties

At December 31, 2007, we owned interests in a total of 500 *gross wells*, of which 284 were *producing*, 191 were shut-in or temporarily abandoned and 25 were injection or saltwater wells. We owned an average 55% *working interest* in the 284 gross (155 *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 2.9 million barrels (*MMBL*) of oil, 91.2 billion cubic feet (*Bcf*) of natural gas and 3.6 million barrels (*Bbls*) of natural gas liquids at December 31, 2007. Substantially all of our properties are located onshore in Texas, Louisiana, Colorado, Mississippi, and shallow inland and offshore waters of Louisiana.

Proved Reserves

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

	2007	2006	2005
Crude Oil (*MBbl*)			
Developed	2,266	2,250	2,423
Undeveloped	637	251	285
Total	2,903	2,501	2,708
Natural Gas (*MMcf*)			
Developed	67,997	27,146	19,658
Undeveloped	23,242	4,242	4,992
Total	91,239	31,388	24,650
Natural Gas Liquids (*Bbls*)			
Developed	2,684	—	—
Undeveloped	906	—	—
Total	3,590	—	—
Total (*MMcfe*)	130,198	46,394	40,898

Approximately 75% of our total *proved reserves* was classified as proved developed at December 31, 2007.

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.

	2007	2006	2005
Future cash inflows	$ 1,125,374,500	$ 313,312,927	$ 425,080,357
Future production and development costs:			
Production	258,028,900	108,693,762	101,677,305
Development	65,779,100	26,229,488	27,467,896
Future cash flows before income taxes	801,566,500	178,389,677	295,935,156
Future income taxes	(198,920,968)	(43,534,046)	(91,664,228)
Future net cash flows after income taxes	602,645,532	134,855,631	204,270,928
10% annual discount for estimated timing of cash flows	(203,122,453)	(57,442,604)	(85,873,789)
Standardized measure of discounted future net cash flows	$ 399,523,079	$ 77,413,027	$ 118,397,139

The average sales prices utilized in the estimation of our proved reserves were $89.91 per Bbl, $6.86 per Mcf and $66.34 per Bbl, $57.67 per Bbl and $5.40 per Mcf, and $57.79 per Bbl and $10.90 per Mcf, at December 31, 2007, 2006 and 2005, respectively.

Significant Properties

Summary information on our properties with *proved reserves* is set forth below as of December 31, 2007.

	Productive Wells		Proved Reserves				Present Value (1)
	Gross Productive Wells	Net Productive Wells	Crude Oil	Natural Gas	Natural Gas Liquids	Total	Amount
			(MBbl)	*(MMcf)*	*(MBbl)*	*(MMcfe)*	*($M)*
Texas	222	116	1,797	77,961	3,318	108,652	436,396
Louisiana	31	17	755	8,063	272	14,225	75,145
Colorado	30	22	301	4,095	—	5,901	14,879
Mississippi	1	—	50	—	—	300	949
Offshore	—	—	—	1,120	—	1,120	4,028
Total	284	155	2,903	91,239	3,590	130,198	531,397

(1) The average sales prices used in the estimation of our proved reserves were $89.91 per Bbl, $6.86 per Mcf and $66.34 per Bbl at December 31, 2007.

All information set forth herein relating to our proved reserves, estimated future net cash flows and present values is taken or derived from reports prepared by Netherland, Sewell & Associates, Inc., 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, natural gas and natural gas liquids, 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.

	2007	2006	2005
Production			
Oil (*Bbl*)	408,864	184,881	177,833
Natural gas (*Mcf*)	9,067,777	1,542,423	1,482,250
Natural gas liquids *(Bbl)*	285,907	—	—
Total (*MCFE*)	13,236,403	2,651,709	2,549,248
Revenue			
Oil sales	$ 27,021,298	$ 10,908,030	$ 7,044,429
Natural gas sales	67,867,603	10,569,705	10,507,221
Natural gas liquids sales	14,272,712	—	—
Total	$ 109,161,613	$ 21,477,735	$ 17,551,650
Lease Operating Expenses	$ 23,735,871	$ 7,527,589	$ 5,585,297
Production Data			
Average sales price [(1)]			
Per barrel of oil	$ 66.09	$ 59.00	$ 39.61
Per *Mcf* of natural gas	$ 7.48	$ 6.85	$ 7.09
Per barrel of natural gas liquids	$ 49.92	$ —	$ —
Per *MCFE*	$ 8.25	$ 8.10	$ 6.89
Average expenses per *MCFE*			
Lease operating	$ 1.79	$ 2.84	$ 2.19
Exploration expenses	$ 0.23	$ 0.19	$ 1.54
Depreciation, depletion and amortization	$ 2.29	$ 1.49	$ 1.23
General and administrative[(2)]	$ 1.10	$ 3.29	$ 1.48

(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 $8.02, $8.34, and $8.43 in 2007, 2006 and 2005, respectively.

(2) Non-cash stock option expense related to our adoption of SFAS 123R on January 1, 2006 was $0.32 and $1.39 per mcfe in 2007 and 2006, respectively.

Productive Wells

The following table shows the number of producing wells we own by location at December 31, 2007:

	Gross Oil Wells	Net Oil Wells	Gross Gas Wells	Net Gas Wells
Texas	32	16	190	100
Louisiana	9	5	22	12
Colorado	22	16	8	6
Mississippi	1	—	—	—
Offshore	—	—	—	—
Total	64	37	220	118

In addition, we have 191 inactive wells (105 net) and 25 salt water disposal wells (14 net).

Developed and Undeveloped Acreage

The following table shows the developed and undeveloped acreage that we own, by location, at December 31, 2007. Developed acreage is acreage spaced or assigned to productive wells. 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* 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.

	Developed		Undeveloped	
	Gross Acres	Net Acres	Gross Acres	Net Acres
Texas	71,967	43,035	72,365	48,969
Louisiana	7,261	3,975	4,484	1,469
Colorado	2,960	2,072	14,322	10,742
Mississippi	80	29	—	—
Total	82,268	49,111	91,171	61,180

Drilling Results

The following table shows the results of the oil and gas wells drilled and completed for each of the last three fiscal years ended December 31, 2007. There were no oil wells drilling during this time period.

	Gross Gas Wells	Net Gas Wells
2007		
Development	9	1.07
Exploratory	8	1.65
Dry	4	0.72
Total	21	3.44
2006		
Development	4	3.50
Exploratory	—	—
Dry	—	—
Total	4	3.50
2005		
Development	1	0.75
Exploratory	—	—
Dry	2	0.78
Total	3	1.53

At December 31, 2007, we had 4 gross (0.54 net) exploratory and 3 gross (0.74 net) development wells in progress.

Costs Incurred

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

	2007	2006	2005
Property Acquisitions:			
Proved	$ 238,036,360	$ —	$ 142,867
Unproved	30,407,525	8,745,363	1,244,975
Development Costs	30,814,788	6,465,719	6,171,241
Exploration Costs	13,405,017	10,783,663	3,157,841
Total	$ 312,663,690	$ 25,994,745	$ 10,716,924

Property Dispositions

The following table shows oil and gas property dispositions:

	2007	2006	2005
Oil and gas properties	$ —	$ —	$ 31,337
Accumulated DD&A	—	—	—
Oil and gas properties, net	$ —	$ —	$ 31,337

As a result of these sales, we recorded a loss on sale of $13,022 in 2005.

Marketing

We sell substantially all of our crude oil and natural gas production to purchasers pursuant to sales contracts that typically have a 30 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 20, 2008, 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, 2007.

PART II

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

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

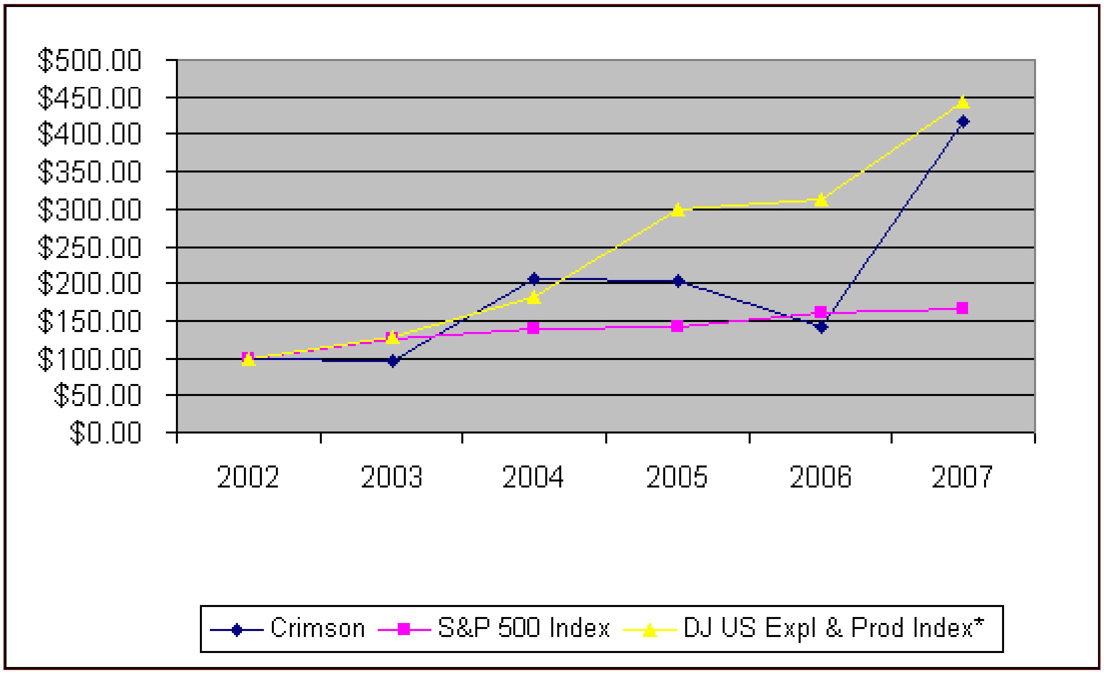
The high and low trading prices for the Common Stock for each quarter in 2007 and 2006 are set forth below. The trading prices represent prices between dealers, without retail mark-ups, mark-downs, or commissions, and may not necessarily represent actual transactions.

	High	Low
2007		
First Quarter	$ 6.20	$ 5.25
Second Quarter	7.55	5.25
Third Quarter	8.35	7.15
Fourth Quarter	19.35	7.65
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

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, 2007 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 the Dow Jones Secondary Oils Stock Index). The comparison assumes $100 was invested on December 31, 2002 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, 2002	$	100.00	$	100.00	$	100.00
December 31, 2003	$	95.45	$	126.38	$	129.42
December 31, 2004	$	206.82	$	137.75	$	181.76
December 31, 2005	$	204.55	$	141.88	$	298.30
December 31, 2006	$	142.05	$	161.20	$	312.14
December 31, 2007	$	418.18	$	166.89	$	445.15

***** 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 20, 2008, there were 5.2 million shares of Common Stock issued and outstanding and held by approximately 224 record holders. Our Common Stock is traded over-the-counter (OTC:BB) 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 H Preferred Stock (on an as converted basis) have the ability to elect all of the directors that the Series G Preferred Stock 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 therefore. 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 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 20, 2008, there were a total of 83,200 shares of preferred stock issued and outstanding in Series G and Series H Preferred Stock.

The 81,000 shares of our Series G Preferred Stock bear a coupon of 8% per year, compounded quarterly, 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.

We were accumulating undeclared dividends, since the original issuance, on a simple or non-compounded basis. During the third quarter 2007, the Company was notified by the majority holder of the Series G Preferred Stock ("Preferred Stock Owner") that they believed that certain provisions of the Certificate of Designations for the Series G resulted in a compounding effect. After reviewing their interpretation, and consulting with legal counsel, the Company and the Preferred Stock Owner settled their dispute and agreed to calculate the accrued, undeclared and unpaid dividends on a compounded basis. This new basis for calculating the dividend accrual was documented in a clarification memo between the parties. In accordance with Statement of Financial Accounting Standards No. 154, "Accounting Changes and Error Corrections" ("SFAS 154"), the change in the method of calculating the accrued, undeclared dividend was a change in accounting estimate necessitated by the "new information" that became available with the written agreement between the parties in the settlement of the dispute. The net effect of the change in the accounting estimate was an increase of $0.7 million in Dividends on Preferred Stock in the Consolidated Statements of Operations for the year ended December 31, 2007, of which approximately $0.4 million was related to prior years, and $0.1 million and $0.2 million was related to the first and second quarters of 2007, respectively.

The 2,200 shares of our Series H Preferred Stock are 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 $2.2 million and is senior to all of our outstanding capital stock in liquidation preference other than the Series G Preferred Stock.

Outstanding Options

At December 31, 2007, we had outstanding employee stock options, under our 1994 and 2004 Stock Option and Compensation Plans, to purchase 146,300 (all vested) shares of Common Stock. On February 28, 2005, we established our 2005 Stock Incentive Plan and authorized the issuance of 2.9 million shares of Common Stock pursuant to awards under the plan, of which approximately 2.6 million (863,650 vested) shares were outstanding at December 31, 2007. Options from all plans range in price from $4.50 to $18.10 per share. At December 31, 2007, we had approximately 84,000 stock options available for grant.

Recent Sales of Unregistered Securities

As shown in the table that follows, during 2007 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 or in the case of conversions, exempt under Section 3(a)(9) of the Act. 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
5/8/07	Common Stock	Accredited Investor	750,000	NA	EXCO Acquisition
5/29/07	Common Stock		291,247	$9.00	Series E Preferred Stock Conversion
5/29/07	Common Stock		428,572	$3.50	Series H Preferred Stock Conversion
9/28/07	Common Stock	Accredited Investors	250,000	NA	Compensation to Company's Executive Officers
10/05/07	Common Stock	Accredited Investors	2,818	NA	Director Compensation
12/20/07	Common Stock		50,000	$80.00	Series D Preferred Stock Conversion

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,				
	2007	**2006**	**2005**	**2004**	**2003**
Income Statement Data					
Operating revenues	$ 109,543,208	$21,659,481	$17,682,808	$11,207,673	$11,010,723
Income (loss) from operations (1)	33,616,299	(2,458,685)	637,823	(476,264)	558,774
Net income (loss)	(430,517)	1,858,944	(3,543,239)	8,072,221	(3,024,426)
Dividends on preferred stock	(4,453,872)	(3,648,925)	(3,562,472)	(455,612)	(127,083)
Net income (loss) available to common shareholders	(4,884,389)	(1,789,981)	(7,105,711)	7,616,609	(3,151,509)
Net income (loss), per share of common stock, basic	$ (1.13)	$ (0.55)	$ (2.66)	$ 4.11	$ (1.71)
Weighted average number of shares of common stock outstanding	4,330,282	3,231,000	2,673,882	1,853,503	1,849,255

(1) Our adoption of SFAS 123r on January 1, 2006 resulted in expense of $4.2 million and $3.7 million, in 2007 and 2006, respectively.

	2007	2006	2005	2004	2003
Balance Sheet Data					
Current assets	$ 36,282,857	$ 4,231,983	$ 5,825,078	$ 3,808,878	$ 1,742,689
Total assets	398,736,366	84,702,722	63,114,949	57,876,164	52,428,774
Current liabilities	48,680,537	10,932,155	6,855,735	37,249,217	44,619,652
Long-term liabilities	280,402,748	12,444,784	3,453,952	1,950,304	1,393,607
Other liabilities	—	—	—	—	591,467
Stockholders' equity	$ 69,653,081	$61,325,783	$52,805,262	$18,676,643	$ 5,824,648

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.

Acquisition

On May 8, 2007, we acquired the STGC Properties from EXCO for total consideration, as of the January 1, 2007 effective date, of $285.0 million in cash and 750,000 shares of Crimson common stock valued at approximately $4.6 million on the closing date. After reduction for applicable adjustments for the net results of operations between the effective date and the closing date, and other customary purchase price adjustments, the cash portion of the purchase price paid at closing was $245.4 million, which is subject to a post-closing adjustment. After considerations for typical closing adjustments, $229.0 million of the purchase price was allocated to proved properties and $28.6 million of the purchase price was allocated to unproved properties. The properties acquired include over 200 producing wells in over 30 fields, are 90% natural gas and are approximately 80% proved developed producing by value. We have an average 50% working interest in the properties and operate more than 80% of the value acquired. The cash portion of the purchase price was financed through an amended and restated $400.0 million revolving credit facility and a new $150.0 million second lien credit facility. The acquisition was accomplished by way of conveyance of 100% of the membership interests of Southern G Holdings, LLC ("*SGH*"), a wholly owned subsidiary of EXCO, from EXCO to us.

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, 2007 Compared to Year Ended December 31, 2006

Revenues

Oil and Gas Sales. Revenues from the sale of crude oil, natural gas and natural gas liquids, net of realized gains from our hedging instruments, increased approximately $87.7 million, to $109.2 million in 2007 compared to $21.5 million in 2006. We realized a loss of $3.4 million on our oil hedges and a gain of $6.4 million on our gas hedges in 2007 compared to a loss of $0.8 million for oil hedges and a gain of $0.2 million for gas hedges in 2006. The increase in net revenues was primarily due to the effect of the STGC Properties acquisition in May 2007, which significantly increased our production volumes.

For 2007, sales volumes were 408,864 barrels of crude oil, 9,067,777 mcf of natural gas and 285,907 barrels of natural gas liquids, or 13,236,403 natural gas equivalents (mcfe), compared to 184,881 barrels of crude oil and 1,542,423 mcf of natural gas, or 2,651,709 natural gas equivalents (mcfe) in 2006. On a daily basis, we produced an average of 36,264 mcfe in 2007 compared to a daily average of 7,265 mcfe in 2006.

Oil and gas prices are reported net of the realized effect of our hedging agreements. Prices realized in 2007 were $66.09 per barrel of oil, $7.48 per mcf of natural gas and $49.92 per barrel of natural gas liquids compared to $59.00 per barrel of oil and $6.85 per mcf of natural gas in 2006. No natural gas liquids were sold in 2006. Prices before the effects of the hedging agreements were $74.38 per barrel of oil, $6.78 per mcf of natural gas and $49.92 per barrel of natural gas liquids in 2007 compared to $63.29 per barrel of oil and $6.76 per mcf in 2006. No natural gas liquids were sold in 2006.

Operating Overhead and Other Income. Revenues from these activities increased to $0.4 million in 2007 compared to $0.2 million in 2006 due to the increase in administrative overhead fees charged to partners on the operated acquired STGC Properties.

Costs and Expenses

Lease Operating Expenses. Lease operating expenses for 2007 were $23.7 million, compared to $7.5 million in 2006. The increase was primarily due to the addition of the STGC Properties. On a per unit basis, expenses decreased to $1.79 per mcfe in 2007 from $2.84 per mcfe in 2006, also as a result of higher volumes per well on the STGC Properties.

Exploration Expense. Exploration expense was $3.1 million in 2007 compared to $0.5 million in 2006. Geological and geophysical costs were $1.4 million, dry hole and abandoned property costs were $1.4 million and lease rentals were $0.2 million for 2007. Geological and geophysical costs were $0.2 million, dry hole and abandoned property costs were $68,000 and lease rentals were $0.2 million for 2006. We intend to continue to invest capital in seismic data and lease rental costs as we develop and expand our internal exploratory prospect generation capability.

Depreciation, Depletion and Amortization (DD&A). DD&A expense for 2007 increased to $30.4 million compared to $4.0 million in 2006. On a per unit basis, DD&A expense increased to $2.29 per mcfe in 2007 compared to $1.49 per mcfe in 2006, as a result of the acquisition of the STGC Properties.

Impaired Assets. Impairment expenses were $4.4 million in 2007 and $3.1 million in 2006.

General and Administrative (G&A) Expenses. Our G&A expenses were $14.5 million in 2007 compared to $8.7 million in 2006. Included in G&A expense is a non-cash stock compensation expense of $4.7 million ($0.32 per mcfe) and $3.8 million ($1.39 per mcfe), for 2007 and 2006, respectively. The $5.8 million increase was primarily due to higher personnel costs, information technology costs, professional fees and office rent incurred in expanding our infrastructure after the acquisition of the STGC Properties. On a per unit basis, G&A expense decreased to $1.10 per mcfe in 2007 from $3.29 per mcfe in 2006, due to the incremental volumes from the acquisition of the STGC Properties.

Interest Expense. Interest expense was $14.9 million in 2007, up from $0.1 million in 2006. Total interest expense increased to $16.2 million for 2007 because of the higher outstanding balances on our credit facilities related to the STGC Properties acquisition; however $1.3 million of that interest related to our Madisonville / Rodessa Prospect was capitalized in 2007.

Other Financing Costs. Other financing costs were $1.3 million in 2007 compared with $0.2 million in 2006. These expenses are comprised primarily of the amortization of capitalized costs associated with our current and former credit facilities and to commitment fees related to the unused portion of the credit facilities.

Unrealized Gain (Loss) on Derivative Instruments. Unrealized gain or loss on derivative instruments is the change in the year-to-date period in the mark-to-market exposure under our commodity price hedging instruments and our interest rate swap. This non-cash charge for 2007 was $18.2 million compared with a non-cash increase in earnings of $6.1 million for 2006. This amount will vary period to period, and will be a function of the hedges in place, the strike prices of those hedges and the current commodity prices at each balance sheet date.

Income Taxes. Our net loss before taxes was $0.8 million in 2007 compared with net income before taxes of $3.3 million in 2006. After adjusting for permanent tax differences, we recorded an income tax benefit of

$0.2 million in 2007 and an income tax expense of $1.4 million in 2006.

Dividends on Preferred Stock. Dividends on preferred stock were $4.5 million in 2007 compared with $3.6 million for 2006. Dividends in 2007 included $4.3 million on the Series G Preferred Stock, $0.1 million on the Series H Preferred Stock and $0.1 million on the Series E Preferred Stock. 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.

Prior to the third quarter of 2007, we had accumulated undeclared dividends, since the original issuance, on a simple or non-compounded basis. During the third quarter, we were notified by the Preferred Stock Owner that they believed that certain provisions of the Certificate of Designations for the Series G resulted in a compounding effect. After reviewing their interpretation, and consulting with legal counsel, we and the Preferred Stock Owner settled their dispute and agreed to calculate the accrued, undeclared and unpaid dividends on a compounded basis. This new basis for calculating the dividend accrual was documented in a clarification memo between the parties. In accordance with SFAS 154, the change in the method of calculating the accrued, undeclared dividend was a change in accounting estimate necessitated by the “new information” that became available with the written agreement between the parties in the settlement of the dispute. The net effect of the change in the accounting estimate was an increase of $0.7 million in Dividends on Preferred Stock in the Consolidated Statements of Operations for the year ended December 31, 2007, of which approximately $0.4 million was related to prior years, and $0.1 million and $0.2 million was related to the first and second quarters of 2007, respectively.

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 $0.5 million in 2006 and $3.9 million in 2005. Geological and geophysical costs were $0.2 million, dry hole and abandoned property costs were $68,000 and lease rentals were $0.2 million for 2006. Geological and geophysical costs were $0.4 million and dry hole and abandoned property costs were $3.5 million for 2005.

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.

Impaired Assets. Impairment expenses were $3.1 million in 2006 compared to $0.5 million in 2005. The expense in 2006 included an impairment 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.

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.

Critical Accounting Policies

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.

Impairments

We assess all of our properties for possible impairment on an annual basis based on geological trend analysis, changes in proved reserves or relinquishment of acreage. When impairment occurs, the adjustment is recorded to accumulated depletion.

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 2007, we increased our ARO to include the new wells acquired from EXCO in May 2007. 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 December 2007, the Financial Accounting Standards Board (FASB) issued a revision to SFAS No. 141 “Business Combinations” (SFAS No. 141(R)). The revision broadens the definition of a business combination to include all transactions or other events in which control of one or more businesses is obtained. Further, the statement establishes principles and requirements for how an acquirer recognizes assets acquired, liabilities assumed and any non-controlling interests acquired. SFAS No. 141(R) is effective for business combination transactions for which the acquisition date is on or after the beginning of the first reporting period beginning on or after December 15, 2008. Early adoption is prohibited. We are currently evaluating the provisions of SFAS No. 141(R) and assessing the impact it may have on us.

In February 2007, the FASB issued SFAS No. 159, “The Fair Value Option for Financial Assets and Financial Liabilities,” which permits entities to measure various financial instruments and certain other items at fair value. SFAS No. 159 will be effective for us in the first quarter of 2008. At the present time, we do not expect to apply the provisions of SFAS No. 159.

In September 2006, the FASB issued SFAS No. 157 “Fair Value Measurements.” SFAS No. 157 defines fair value, establishes a framework for measuring fair value, and expands disclosures about fair value measurements. The statement does not require any new fair value measurements for us. This statement is effective for financial statements issued for fiscal years beginning after November 15, 2007. The adoption of SFAS No. 157 is not expected to materially impact our Consolidated Financial Statements; however, it will result in additional disclosures related to the use of fair values in the financial statements.

Contractual Obligations

The following table provides information about our contractual cash obligations as of December 31, 2007:

	Long-term debt	Operating leases	Asset retirements	FIN 48 (1)
2008	$ 100,609	$ 1,020,413	$ 1,407,347	$ —
2009	46,305	650,280	365,577	—
2010	17,921	613,302	324,150	—
2011	110,000,000	551,325	537,485	—
2012	150,000,000	551,325	107,530	—
More than 5 years	—	597,269	4,813,402	—
Total	$ 260,164,835	$ 3,983,914	$ 7,555,491	$ 518,219

(1) We are unable to determine when this obligation may be required to be paid, if at all.

Liquidity and Capital Resources

At December 31, 2007, our current liabilities exceeded our current assets by approximately $12.4 million due to increased capital expenditures in the fourth quarter of 2007, while at December 31, 2006 our current liabilities exceeded our current assets by $6.7 million. At December 31, 2007, we had $90.0 million available under our credit agreements. During 2007, we generated $69.6 million in cash flow from operations compared to $14.3 million in 2006. 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 2008. Our level of exploratory capital expenditures for 2008 will be determined based on available cash flow and other appropriate sources of available capital.

Credit Facilities

On May 8, 2007, the Company entered into a $400.0 million amended and restated credit agreement (the *“Senior Credit Agreement”*) with Wells Fargo Bank, National Association, as agent, Wells Fargo Bank, National Association and The Royal Bank of Scotland, plc, which amended and restated the Company’s existing senior secured revolving credit facility dated as of July 15, 2005, as amended. On May 8, 2007, the Company borrowed $122.7 million pursuant to the Senior Credit Agreement to pay the consideration under the EXCO Purchase Agreement (defined below) and to refinance certain existing indebtedness of the Company. On May 31, 2007, the Senior Credit Agreement was amended to provide for up to a $5.0 million swing line facility.

Borrowings under the Senior Credit Agreement are subject to a borrowing base limitation based on the Company’s proved oil and gas reserves. The borrowing base was reaffirmed at $200.0 million on November 1, 2007 and is subject to semi-annual redeterminations. The Senior Credit Agreement has a term of four years, and all principal amounts, together with all accrued and unpaid interest, will be due and payable in full on

May 8, 2011. The Senior Credit Agreement also provides for the issuance of letters-of-credit up to a $5.0 million sub-limit.

Advances under the Senior 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" or (2) the Federal Funds rate plus a margin of 0.50%, plus a 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, two, three and nine months may be selected by the Company. A commitment fee of 0.375% on the unused portion of the borrowing base will accrue, and be payable quarterly in arrears.

In addition, on May 8, 2007, the Company entered into a five-year second lien credit agreement (the "*Second Lien Credit Agreement*") with Credit Suisse, as agent, which provides for term loans to be made to the Company in a single draw in an aggregate principal amount of $150.0 million. On May 8, 2007, the Company borrowed $150.0 million pursuant to the Second Lien Credit Agreement to pay the consideration under the EXCO Purchase Agreement (defined below) and to refinance certain existing indebtedness of the Company. The Second Lien Credit Agreement replaced the Company's existing $150.0 million subordinate credit facility, which was paid off in full and terminated at closing.

The Second Lien Credit Agreement matures on May 8, 2012. Loans under the Second Lien Credit Agreement are subject to floating rates of interest equal to, at the Company's option, the LIBOR rate plus 5.25% or the base rate plus 4.25%; however, as the Company did not obtain gross proceeds of at least $25.0 million from the issuance of Common Stock and/or preferred equity within 180 days from the closing date of the Second Lien Credit Agreement (November 5, 2007), the applicable interest rate is currently the LIBOR rate plus 5.75% or the base rate plus 4.75%. Eurodollar loans of one, two, three and six months may be selected by the Company.

The Senior Credit Agreement and the Second Lien Credit Agreement ("the *Credit Agreements*") are secured by a lien on all the assets of the Company and its active subsidiaries, as well as a security interest in the stock of all the Company's direct and indirect subsidiaries. The obligations under the Second Lien Credit Agreement are subordinate and junior to those under the Senior Credit Agreement.

The Credit Agreements include usual and customary affirmative covenants for credit facilities of the respective types and sizes, as well as customary negative covenants, including, among others, limitations 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, as well as events of default. The Credit Agreements also contain certain financial covenants, including (a) with respect to the Senior Credit Agreement, maintaining (i) a ratio of current assets to current liabilities of at least 1.0 to 1.0, (ii) an interest coverage ratio of EBITDAX (earnings before interest, taxes, depreciation and amortization and exploration expense) to cash interest expense of 3.0 to 1.0 and (iii) a minimum leverage ratio of total debt to EBITDAX of 3.50 to 1.00 and (b) with respect to the Second Lien Credit Agreement, maintaining (i) a minimum leverage ratio of total debt to EBITDAX of 4.00 to 1.00 for the fiscal quarters ending on or before December 31, 2007, 3.50 to 1.00 for the fiscal quarters ending after December 31, 2007 and ending on or before September 30, 2008 and 3.00 to 1.00 for the fiscal quarters ending after September 30, 2008 and (ii) a PV-10 Ratio (as defined in the Second Lien Credit Agreement) less than 1.25x for a period from September 30, 2007 to December 31, 2007 and less than 1.50x for the period on or after January 1, 2008. EBITDAX is calculated without consideration of unrealized gains and losses related to stock derivatives accounted for under variable accounting rules or to commodity hedges. At December 31, 2007, we were in compliance with the aforementioned covenants.

In connection with the Credit Agreements, the Company also entered into new crude oil and natural gas hedges, which combined with the Company's existing commodity price hedge positions, result in approximately 75% of production from the then estimated proved developed reserves for the Company being hedged through the end of 2011. The Company used a series of swaps and costless collars to accomplish the hedging requirements. The Company also constructively fixed the base LIBOR rate on $200.0 million of its variable rate debt through July 8, 2009 by entering into interest rate swaps at a swap price of 5.02%.

At March 20, 2008, we had $85.8 million outstanding under the Senior Credit Agreement and $150.0 million outstanding under the Second Lien Credit Agreement, with availability under the Senior Credit Agreement of $114.2 million.

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, natural gas and natural gas liquids 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	Natural Gas	Natural Gas Liquids [2]	Per Equivalent MCF
	(per Bbl)	*(per Mcf)*	*(per Bbl)*	
2007				
First	$ 60.28	$ 7.07	$ —	$ 8.33
Second	62.66	7.64	43.29	8.09
Third	66.47	7.60	45.17	8.18
Fourth	69.41	7.28	55.19	6.78
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

(1) Average sales price are shown net of the settled amounts of our oil and gas hedge contracts.
(2) Natural gas liquids became a significant addition to our reserves since the acquisition of the STGC properties in May 2007.

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. To manage this risk, we have entered into interest rate swap agreements with a total notional amount of $200.0 million related to our Senior Credit Agreement. As of December 31, 2007, the interest rate swap had an estimated net fair value liability of $4.0 million. Under these agreements, we receive interest at a floating rate equal to one-month LIBOR plus the applicable spread under our credit facility and pay interest at a fixed rate of 5.02% plus the applicable spread under our credit facility. Assuming our current level of borrowings and considering the effect of the interest rate swap agreements, a 100 basis point increase in the interest rate we pay under our credit facility would not have had a material impact on our interest expense for the year ended December 31, 2007.

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 2007 and 2006, 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, 2007.

Crude Oil		Volume/ Month	Price/ Unit	Fair Value
Jan 2008-Dec 2008	Swap	6,500 Bbls	$76.40	$ (1,272,705)
Jan 2008-Dec 2008	Collar	18,800 Bbls	Floor $67.11-$70.50 Ceiling	(5,035,275)
Jan 2009-Dec 2009	Swap	5,200 Bbls	$74.20	(808,770)
Jan 2009-Dec 2009	Collar	12,800 Bbls	Floor $66.55-$71.40 Ceiling	(2,535,973)
Jan 2010-Dec 2010	Swap	4,250 Bbls	$72.32	(619,406)
Jan 2010-Dec 2010	Collar	9,000 Bbls	Floor $65.28-$70.60 Ceiling	(1,625,040)
Jan 2011-Dec 2011	Swap	3,300 Bbls	$70.74	(503,056)
Jan 2011-Dec 2011	Collar	7,000 Bbls	Floor $64.50-$69.50 Ceiling	(1,270,613)
Natural Gas				
Jan 2008-Dec 2008	Swap	47,000 Mmbtu	$8.97	643,221
Jan 2008-Dec 2008	Collar	659,000 Mmbtu	Floor $8.19-$9.65 Ceiling	5,439,887
Jan 2009-Dec 2009	Swap	36,000 Mmbtu	$8.32	(80,606)
Jan 2009-Dec 2009	Collar	475,000 Mmbtu	Floor $7.90-$9.45 Ceiling	(163,512)
Jan 2010-Dec 2010	Swap	29,000 Mmbtu	$7.88	(223,875)
Jan 2010-Dec 2010	Collar	351,000 Mmbtu	Floor $7.57-$9.05 Ceiling	(1,483,792)
Jan 2011-Dec 2011	Collar	266,000 Mmbtu	Floor $7.32-$8.70 Ceiling	(1,712,690)
Total fair value liability				$ (11,252,205)
Current portion				$ (430,775)
Noncurrent portion				$ (10,821,430)

We also entered into the following interest rate swap during the period:

Interest rate		Notional Amount	Fixed Rate	
Dec 8, 2007-Jul 8, 2009	Swap	$200,000,000	5.02%	
Current fair value liability				$ (2,074,476)
Noncurrent fair value liability				$ (1,925,589)
Net fair value liability				$ (4,000,065)

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 liability for derivative instruments of $15.3 million and a net asset of $2.9 million at December 31, 2007 and 2006, respectively. As a result of these agreements, we recorded a non-cash charge, for unsettled contracts, of $18.2 million, a non-cash increase in earnings of $6.1 million and a non-cash charge of $1.6 million for the years ended December 31, 2007, 2006 and 2005, respectively. The estimated change in fair value of the derivatives is reported in Other Income (Expense) as unrealized gain (loss) on derivative instruments.

For settled contracts, we realized gains, reflected as additions in oil and gas revenues, of $3.0 million for the year ended December 31, 2007 and losses, reflected as reductions in oil and gas revenues, of $0.6 million and $3.9 million for the years ended December 31, 2006 and 2005, 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

Disclosure 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 Securities and Exchange Commission'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 three months ended December 31, 2007, there has been no change to our internal controls over financial reporting that materially affected, or is reasonably likely to materially affect, these controls.

Management's Report on Internal Control over Financial Reporting

Management's annual report on internal control over financial reporting as of December 31, 2007 is in "Item 8. Financial Statements and Supplementary Data" in Part II of this Annual Report on Form 10-K.

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, 2007.

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, 2007.

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, 2007.

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, 2007.

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, 2007.

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.

NGL. *Natural gas liquids*. Natural gas liquids are a component of natural gas and include ethane, propane, butane, isobutane and natural gas. These liquids are used as petrochemical feedstocks, home heating fuels and refinery blending and are measured in barrels (Bbls.)

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:

Report of Management
Report of Independent Registered Public Accounting Firm
Consolidated Balance Sheets at December 31, 2007 and 2006
Consolidated Statements of Operations for the years ended December 31, 2007, 2006 and 2005
Consolidated Statements of Stockholders' Equity for the years ended December 31, 2007, 2006 and 2005
Consolidated Statements of Cash Flows for the years ended December 31, 2007, 2006 and 2005
Notes to Consolidated Financial Statements

(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, Inc. and its stockholders (incorporated by reference to Exhibit 2.1 of the Company's Annual Report on Form 10-K for the fiscal year ended December 31, 2005)
2.2	Membership Interest Purchase and Sale Agreement, dated May 8, 2007, by and among EXCO Resources, Inc., Southern G Holdings, LLC, Crimson Exploration Inc. and Crimson Exploration Operating Inc. (incorporated by reference to Exhibit 10.1 of the Company's Current Report on Form 8-K filed May 15, 2007)
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, 2005)
3.2	Certificate of Designation, Preferences and Rights of Series D Preferred Stock (incorporated by reference to Exhibit 3.2 of the Company's Current Report on Form 8-K filed July 5, 2005)
3.3	Certificate of Designation, Preferences and Rights of Cumulative Convertible Preferred Stock, Series E (incorporated by reference to Exhibit 3.3 of the Company's Current Report on Form 8-K filed July 5, 2005)
3.4	Certificate of Designation, Preferences and Rights of Series G Convertible Preferred Stock (incorporated by reference to Exhibit 3.4 of the Company's Current Report on Form 8-K filed July 5, 2005)
3.5	Certificate of Designation, Preferences and Rights of Series H Convertible Preferred Stock (incorporated by reference to Exhibit 3.5 of the Company's Current Report on Form 8-K filed July 5, 2005.)
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)

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

3.7 Certificate of Amendment of Certificate of Incorporation (incorporated by reference to Appendix A to the Company's Definitive Information Statement on Schedule 14C filed August 18, 2006)

4.1 Letter Agreement by and among GulfWest Energy Inc., a Texas corporation, GulfWest Oil & Gas Company and the investors listed on the signature page thereof, dated April 22, 2004 (incorporated by reference to Exhibit 4.2 of the Company's Current Report on Form 8-K filed on May 10, 2004)

4.2 Registration Rights Agreement, dated May 8, 2007, by and between Crimson Exploration Inc. and EXCO Resources, Inc. (incorporated by reference to Exhibit 10.2 of the Company's Current Report on Form 8-K filed May 15, 2007)

4.3 Shareholders Rights Agreement between GulfWest Energy Inc. and OCM GW Holdings, LLC dated February 28, 2005 (incorporated by reference to Exhibit 99(e) of the Schedule 13D, Reg. No. 005-54301, filed on March 10, 2005)

4.4 Omnibus and Release Agreement among GulfWest Energy Inc., OCM GW Holdings, LLC and those signatories set forth on the signature page thereto, dated as of February 28, 2005 (incorporated by reference to Exhibit 99(f) of the Schedule 13D, Reg. No. 005-54301, filed on March 10, 2005)

4.9 Subscription Agreement among OCM GW Holdings, LLC, Allan D. Keel and those individuals listed on the signature page thereto, dated February 28, 2005 (incorporated by reference to Exhibit 99(c) to the Schedule 13D, Reg. No. 005-54301, filed on March 10, 2005)

4.10 Registration Rights Agreement, dated March 20, 2006, among Crimson Exploration Inc. and the stockholders of Core Natural Resources, Inc. (incorporated by reference to Exhibit 4.11 of Amendment No. 1 to the Company's Annual Report on Form 10-K for the year ended December 31, 2005)

#10.1 Employment Agreement between Allan D. Keel and GulfWest Energy, Inc., dated February 28, 2005 (incorporated by reference to Exhibit 10.1 of the Company's Annual Report on Form 10-K for the year ended December 31, 2004)

#10.2 Employment Agreement between E. Joseph Grady and GulfWest Energy, Inc., dated February 28, 2005 (incorporated by reference to Exhibit 10.2 of the Company's Annual Report on Form 10-K for the year ended December 31, 2004)

#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 May 18, 2001 (incorporated by reference to Exhibit I of the Company's Proxy Statement on Form DEF 14A, filed on April 16, 2001)

#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 for the year ended December 31, 2004)

#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 for the year ended December 31, 2004)

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

#10.6	Form of GulfWest Energy Inc. 2005 Stock Incentive Plan Stock Option Agreement (incorporated by reference to Exhibit 10.6 of Amendment No. 1 to the Company's Annual Report on Form 10-K for the year ended December 31, 2005)
#10.8	Form of Indemnification Agreement for directors and officers (incorporated by reference to Exhibit 10.3 to the Company's Form 8-K filed on July 21, 2005)
10.9	Letter Agreement among D.B. Zwirn Special Opportunities Fund, LP, GulfWest Oil & Gas, and Drawbridge Special Opportunities Fund, LP, dated January 7, 2005 (incorporated by reference to Exhibit 10.13 of the Company's Annual Report on Form 10-K for the year ended December 31, 2004)
10.10	Series G Subscription Agreement between GulfWest Energy Inc. and OCM GW Holdings, LLC dated February 28, 2005 (incorporated by reference to Exhibit 99(a) of the Schedule 13D, Reg. No. 005-54301, filed on March 10, 2005)
10.11	Series A Subscription Agreement between GulfWest Oil & Gas Company and OCW GW Holdings, LLC dated February 28, 2005 (incorporated by reference to Exhibit 99(b) of the Schedule 13D, Reg. No. 005-54301, filed on March 10, 2005)
10.14	Oil and Gas Property Acquisition, Exploration and Development Agreement with Summit Investment Group-Texas, L.L.C. effective December 1, 2001 (incorporated by reference to Exhibit 10.8 of the Company's Registration Statement No. 333-116048 on Form S-1)
#10.16	Employment Agreement between Tracy Price and GulfWest Energy Inc., dated April 1, 2005. (incorporated by reference to Exhibit 10.22 of the Company's Post Effective Amendment No. 1 to the Registration Statement No. 333-116048 on Form S-1)
#10.17	Employment Agreement between Tommy Atkins and GulfWest Energy Inc., dated April 1, 2005 (incorporated by reference to Exhibit 10.23 of the Company's Post Effective Amendment No. 1 to the Registration Statement No. 333-116048 on Form S-1)
#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 Company's Post Effective Amendment No. 1 to the Registration Statement No. 333-116048 on Form S-1)
#10.20	Summary terms of June 2005 Director Compensation Plan (incorporated by reference to page 47 of the Prospectus to the Company's Post-Effective Amendment No. 1 to the Registration Statement No. 333-116048 on Form S-1)
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 time a party thereto. (incorporated by reference to Exhibit 10.1 to the Company's Form 8-K, Reg. No. 001-12108, filed on July 21, 2005.)
#10.22	Form of director and officer restricted stock grant (incorporated by reference to Exhibit 10.3 to the Company's Form 8-K filed on July 21, 2005)
10.23	First Amendment to Credit Agreement, dated as of March 6, 2006, among Crimson Exploration, Inc., Crimson Exploration Operating, Inc., LTW Pipeline Co., and Wells Fargo Bank, National Association (incorporated by reference to Exhibit 10.24 of the Company's Annual Report on Form 10-K for the fiscal year ended December 31, 2005)

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

10.25	Second Amendment to Credit Agreement, dated as of August 31, 2006, among Crimson Exploration Inc., Crimson Exploration Operating, Inc., LTW Pipeline Co., and Wells Fargo Bank, N.A. (incorporated by reference to Exhibit 10.2 to the Company's Form 8-K, Reg. No. 000-21644, filed on September 7, 2006)
10.26	Subordinate Credit Agreement, dated as of August 31, 2006, among Crimson Exploration Inc., Wells Fargo Energy Capital, Inc., as agent and a lender, and each lender from time to time party thereto. (incorporated by reference to Exhibit 10.1 to the Company's Form 8-K, Reg. No. 000-21644, filed on September 7, 2006)
10.27	Amended and Restated Credit Agreement, dated as of May 8, 2007, among Crimson Exploration Inc., as borrower, Wells Fargo Bank, National Association, as agent, Wells Fargo Bank, National Association and The Royal Bank of Scotland, plc, as co-lead arrangers and joint bookrunners, and each lender from time to time party thereto. (incorporated by reference to Exhibit 10.3 to the Company's Current Report on Form 8-K filed May 15, 2007)
10.28	Second Lien Credit Agreement, dated as of May 8, 2007, among Crimson Exploration Inc., as borrower, Credit Suisse, as agent, and each lender from time to time party thereto. (incorporated by reference to Exhibit 10.4 to the Company's Current Report on Form 8-K filed May 15, 2007)
#10.29	Form of executive officer restricted stock grant for grants outside the 2005 Stock Incentive Plan (incorporated by reference to Exhibit 99.1 to the Company's Current Report on Form 8-K filed August 7, 2007)
10.30	Amendment No.1, dated as of June 5, 2007, to the Second Lien Credit Agreement, dated as of May 8, 2007, among Crimson Exploration Inc., as borrower, Credit Suisse, as agent, and each lender from time to time party thereto. (incorporated by reference to Exhibit 10.1 to the Company's Current Report on Form 8-K filed June 8, 2007)
10.31	Amended and Restated Credit Agreement, dated as of May 31, 2007, among Crimson Exploration Inc., as borrower, Wells Fargo Bank, National Association, as agent, Wells Fargo Bank, National Association and The Royal Bank of Scotland, plc, as co-lead arrangers and joint bookrunners, and each lender from time to time party thereto. (incorporated by reference to Exhibit 10.1 to the Company's Current Report on Form 8-K filed June 6, 2007
22.1	Subsidiaries of the Registrant (included on page 2) of this Annual Report.
*23.1	Consent of Grant Thornton LLP
*23.2	Consent of Netherland, Sewell & Associates, Inc.
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; filed herewith.
*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; filed herewith.

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

*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 herewith.

*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 herewith.

* filed herewith

management contract or compensatory plan or arrangement

S I G N A T U R E S

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: August 8, 2008

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

POWER OF ATTORNEY

Know all men by these presents, that the undersigned 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 capacity and on the dates indicated.

Signature	Title	Date
/s/ Terence Lynch Terence Lynch	Corporate Controller and Chief Accounting Officer	August 8, 2008

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 Allan D. Keel	President, Chief Executive Officer and Director	August 8, 2008
/s/ E. Joseph Grady E. Joseph Grady	Senior Vice President and Chief Financial Officer	August 8, 2008
* B. James Ford	Director	August 8, 2008
* Lon Mc Cain	Director	August 8, 2008
* Lee B. Backsen	Director	August 8, 2008
* Adam C. Pierce	Director	August 8, 2008

*By: /s/ Allan D. Keel
Allan D. Keel
As attorney-in-fact pursuant to a
Power-of-Attorney previously granted

CRIMSON EXPLORATION INC.

FINANCIAL REPORT

DECEMBER 31, 2007

C O N T E N T S

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 MANAGEMENT ON INTERNAL CONTROL OVER FINANCIAL REPORTING

Management of the Company is responsible for the preparation and integrity of the consolidated financial statements appearing in the Annual Report on Form 10-K/A. The financial statements were prepared in conformity with accounting principles generally accepted in the United States and include amounts that are based on management's best estimates and judgments.

Management of the Company is responsible for establishing and maintaining effective internal control over financial reporting as such term is defined in Rule 13a-15(f) under the Securities Exchange Act of 1934 ("Exchange Act"). The Company's internal control over financial reporting is designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of the consolidated financial statements. Our internal control over financial reporting is supported by a program of appropriate reviews by management, written policies and guidelines, careful selection and training of qualified personnel and a written code of business conduct adopted by our Company's board of directors, applicable to all Company directors and all officers and employees of our Company and subsidiaries.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements and even when determined to be effective, can only provide reasonable assurance with respect to financial statement preparation and presentation. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions or that the degree of compliance with the policies or procedures may deteriorate.

Management assessed the effectiveness of the Company's internal control over financial reporting as of December 31, 2007. In making this assessment, management used the criteria set forth by the Committee of Sponsoring Organizations of the Treadway Commission (COSO) in *Internal Control —Integrated Framework*. Based on our assessment, management believes that the Company maintained effective internal control over financial reporting as of December 31, 2007.

/s/ Allan D. Keel
Allan D. Keel
President and Chief Executive Officer

/s/ E. Joseph Grady
E. Joseph Grady
Senior Vice President and Chief Financial Officer

/s/ Terence Lynch
Terence Lynch
Corporate Controller
Chief Accounting Officer

Houston, Texas
August 8, 2008

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, 2007 and 2006, and the related consolidated statements of operations, stockholders' equity, and cash flows for each of the three years in the period ended December 31, 2007. 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, 2007 and 2006, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2007 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.*" In addition, as described in Note 8 to the consolidated financial statements, effective January 1, 2007 the Company adopted the provisions of Financial Accounting Standards Board Interpretation No. 48, "*Accounting for Uncertainty in Income Taxes*."

/s/ GRANT THORNTON LLP

Houston, Texas
March 31, 2008

CRIMSON EXPLORATION INC. AND SUBSIDIARIES
CONSOLIDATED BALANCE SHEETS

ASSETS

	December 31, 2007	December 31, 2006
CURRENT ASSETS		
Cash and cash equivalents	$ 4,882,511	$ 23,321
Accounts receivable – trade, net of allowance for doubtful accounts of $215,015 and $118,110, respectively	30,034,558	3,283,270
Prepaid expenses	230,870	225,304
Derivative instruments	—	700,088
Deferred tax asset, net	1,134,918	—
Total current assets	36,282,857	4,231,983
PROPERTY AND EQUIPMENT		
Oil and gas properties, using the successful efforts method of accounting	407,905,609	94,798,478
Other property and equipment	2,710,995	1,713,911
Less accumulated depreciation, depletion and amortization	(54,128,002)	(19,965,497)
Total property and equipment, net	356,488,602	76,546,892
NONCURRENT ASSETS		
Deposits	94,591	49,502
Debt issuance cost, net	3,982,023	449,583
Deferred charges	1,400,000	—
Derivative instruments	—	2,233,800
Deferred tax asset, net	488,293	1,190,962
Total other assets	5,964,907	3,923,847
TOTAL ASSETS	$ 398,736,366	$ 84,702,722

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, 2007	December 31, 2006
CURRENT LIABILITIES		
Current portion of long-term debt	$ 100,609	$ 91,093
Accounts payable – trade	41,432,777	9,778,359
Accrued expenses	3,234,553	736,406
Income taxes payable	—	75
Asset retirement obligations	1,407,347	185,414
Derivative instruments	2,505,251	—
Deferred tax liability, net	—	140,808
Total current liabilities	48,680,537	10,932,155
NONCURRENT LIABILITIES		
Long-term debt, net of current portion	260,064,226	8,414,993
Asset retirement obligations	6,148,144	4,029,791
Derivative instruments	12,747,019	—
Other noncurrent liabilities	1,443,359	—
Total noncurrent liabilities	280,402,748	12,444,784
Total liabilities	329,083,285	23,376,939
COMMITMENTS AND CONTINGENCIES		
STOCKHOLDERS' EQUITY		
Preferred stock (see Note 6)	832	1,032
Common stock (see Note 6)	5,128	3,334
Additional paid-in capital	89,507,073	79,693,736
Retained deficit	(19,859,952)	(18,372,319)
Total stockholders' equity	69,653,081	61,325,783
TOTAL LIABILITIES AND STOCKHOLDERS' EQUITY	$ 398,736,366	$ 84,702,722

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,		
	2007	2006	2005
OPERATING REVENUES			
Oil and gas sales	$ 109,161,613	$ 21,477,735	$ 17,551,650
Operating overhead and other income	381,595	181,746	131,158
Total operating revenues	109,543,208	21,659,481	17,682,808
OPERATING EXPENSES			
Lease operating expenses	23,735,871	7,527,589	5,585,297
Exploration expenses	3,105,090	511,495	3,925,523
Depreciation, depletion and amortization	30,361,159	3,951,645	3,130,647
Impaired assets	4,362,186	3,149,980	532,396
Asset retirement obligations	504,653	245,327	59,850
General and administrative	14,541,780	8,729,674	3,772,771
(Gain) loss on sale of assets	(683,830)	2,456	38,501
Total operating expenses	75,926,909	24,118,166	17,044,985
INCOME (LOSS) FROM OPERATIONS	33,616,299	(2,458,685)	637,823
OTHER INCOME (EXPENSE)			
Interest expense	(14,949,358)	(108,961)	(1,302,894)
Other financing costs	(1,321,661)	(228,320)	(1,955,501)
Loss from equity in investments	—	(1,843)	(71,679)
Unrealized gain (loss) on derivative instruments	(18,186,158)	6,082,058	(1,642,643)
Total other income (expense)	(34,457,177)	5,742,934	(4,972,717)
INCOME (LOSS) BEFORE INCOME TAXES	(840,878)	3,284,249	(4,334,894)
INCOME TAX (EXPENSE) BENEFIT	410,361	(1,425,305)	791,655
NET INCOME (LOSS)	(430,517)	1,858,944	(3,543,239)
DIVIDENDS ON PREFERRED STOCK (PAID 2007-$702,948; 2006-$154,875; 2005-$1,127,643)	(4,453,872)	(3,648,925)	(3,562,472)
NET LOSS AVAILABLE TO COMMON SHAREHOLDERS	$ (4,884,389)	$ (1,789,981)	$ (7,105,711)
NET LOSS PER SHARE			
BASIC	$ (1.13)	$ (0.55)	$ (2.66)
DILUTED	$ (1.13)	$ (0.55)	$ (2.66)
WEIGHTED AVERAGE SHARES OUTSTANDING			
BASIC	4,330,282	3,231,000	2,673,882
DILUTED	4,330,282	3,231,000	2,673,882

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, 2007, 2006 and 2005

	NUMBER OF SHARES						
	PREFERRED STOCK	COMMON STOCK	PREFERRED STOCK	COMMON STOCK	ADDITIONAL PAID-IN CAPITAL	RETAINED DEFICIT	TOTAL STOCKHOLDERS' EQUITY
BALANCE, DECEMBER 31, 2004	25,290	1,939,513	$ 253	$ 1,940	$ 34,079,956	$ (15,405,506)	18,676,643
Common stock issued for services and fees	—	6,319	—	6	53,273	—	53,279
Preferred A issued	2,000	—	20	—	1,499,980	—	1,500,000
Preferred G issued	81,000	—	810	—	36,686,311	—	36,687,121
Preferred A converted	(3,250)	464,286	(33)	464	(431)	—	—
Preferred F converted	(340)	17,000	(3)	17	(14)	—	—
Preferred H converted	(1,450)	207,143	(14)	207	(193)	—	—
Dividends paid on preferred stock	—	48,598	—	49	446,253	—	446,302
Options and warrants exercised	—	216,323	—	216	112,583	—	112,799
Current year net loss	—	—	—	—	—	(3,543,239)	(3,543,239)
Dividends paid on preferred stock	—	—	—	—	—	(1,127,643)	(1,127,643)
BALANCE, DECEMBER 31, 2005	103,250	2,899,182	1,033	2,899	72,877,718	(20,076,388)	52,805,262
Share based compensation	—	28,644	—	29	3,876,985	—	3,877,014
Stock options exercised	—	10,700	—	11	48,139	—	48,150
Preferred H converted	(30)	4,287	(1)	4	(3)	—	—
Acquisition of oil and gas leases	—	369,789	—	370	2,736,043	—	2,736,413
Current year net income	—	—	—	—	—	1,858,944	1,858,944
Dividends paid on preferred stock	—	21,000	—	21	154,854	(154,875)	—
BALANCE, DECEMBER 31, 2006	103,220	3,333,602	1,032	3,334	79,693,736	(18,372,319)	61,325,783
Cumulative effect of adopting FIN 48	—	—	—	—	—	(354,168)	(354,168)
Share based compensation	—	252,818	—	253	4,531,930	—	4,532,183
Stock options and warrants exercised	—	4,000	—	5	4,795	—	4,800
Preferred H converted	(3,020)	431,430	(30)	430	(400)	—	—
Preferred E converted	(9,000)	225,000	(90)	225	(135)	—	—
Preferred D converted	(8,000)	50,000	(80)	50	30	—	—
Acquisition of oil and gas leases	—	750,000	—	750	4,574,250	—	4,575,000
Current year net loss	—	—	—	—	—	(430,517)	(430,517)
Dividends paid on preferred stock	—	81,087	—	81	702,867	(702,948)	—
BALANCE, DECEMBER 31, 2007	83,200	5,127,937	$ 832	$ 5,128	$ 89,507,073	$ (19,859,952)	$ 69,653,081

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, 2007	2006	2005
CASH FLOWS FROM OPERATING ACTIVITIES:			
Net income (loss)	$ (430,517)	$ 1,858,944	$ (3,543,239)
Adjustments to reconcile net income (loss) to net cash provided by operating activities:			
Depreciation, depletion and amortization	30,361,159	3,951,645	3,130,647
Dry holes, abandoned property, impaired assets	5,710,125	3,209,943	3,698,633
Asset retirement obligations	166,883	69,694	59,850
Stock compensation expense	4,738,125	3,819,600	44,164
Debt issuance cost	1,059,033	134,131	1,829,046
Discount on note payable	—	—	502,120
Deferred charges	(1,400,000)	—	—
Deferred tax expense (benefit)	(410,361)	1,425,305	(797,629)
(Gain) loss on sale of assets	(683,830)	2,456	38,501
Loss from equity in investments	—	1,843	71,679
Unrealized (gain) loss on derivative instruments	18,186,158	(6,082,058)	1,642,643
Provision for bad debts	96,904	87,436	30,674
Changes in operating assets and liabilities:			
Increase in accounts receivable – trade, net	(22,648,152)	(161,811)	(1,997,038)
(Increase) decrease in prepaid expenses	(5,566)	24,120	(120,707)
Increase (decrease) in accounts payable and accrued expenses	34,871,687	5,946,284	(1,045,249)
Net cash provided by operating activities	69,611,648	14,287,532	3,544,095
CASH FLOWS FROM INVESTING ACTIVITIES:			
Deposits	(45,089)	—	(39,698)
Proceeds from sale of assets	756,650	7,950	101,905
Acquisition of oil and gas properties	(253,434,220)	—	—
Capital expenditures	(59,048,764)	(21,777,332)	(10,797,961)
Net cash used in investing activities	(311,771,423)	(21,769,382)	(10,735,754)
CASH FLOWS FROM FINANCING ACTIVITIES:			
Proceeds from sale of preferred stock, net	—	—	38,187,121
Proceeds from common stock options and warrants exercised	4,800	48,150	56,450
Payments on debt	(68,571,595)	(18,805,206)	(34,258,132)
Proceeds from debt issuance	320,177,233	26,097,334	4,274,241
Debt issuance cost	(4,591,473)	(309,500)	(323,664)
Dividends paid	—	—	(681,341)
Net cash provided by financing activities	247,018,965	7,030,778	7,254,675
INCREASE (DECREASE) IN CASH AND CASH EQUIVALENTS	4,859,190	(451,072)	63,016
CASH AND CASH EQUIVALENTS, Beginning of year	23,321	474,393	411,377
CASH AND CASH EQUIVALENTS, End of year	$ 4,882,511	$ 23,321	$ 474,393
CASH PAID FOR INTEREST	$ 14,914,194	$ 291,163	$ 2,000,218
CASH PAID FOR INCOME TAXES	$ —	$ 31,000	$ 93,154
NON-CASH STOCK ISSUANCE FOR OIL AND GAS PROPERTIES	$ 4,575,000	$ 2,736,413	$ —

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

In June 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.

In January 2006, we formed Crimson Exploration Operating, Inc. ("CEO"), 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.

In September 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 May 8, 2007, *CEO*, a wholly owned subsidiary of the Company, acquired certain oil and natural gas properties and related assets in the South Texas and Gulf Coast areas of Louisiana and Texas ("the *STGC Properties*") pursuant to a Membership Interest Purchase and Sale Agreement (the "*Purchase Agreement*") from EXCO Resources, Inc. ("*EXCO*") through the acquisition of 100% of the membership interest of Southern G Holdings, LLC ("*SGH*"). These properties were operated under SGH until SGH merged with CEO on December 31, 2007. The consolidated statements of operations include the results of operations of the STGC Properties from May to December 2007.

Segments

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.

Reclassifications

Certain reclassifications have been made to the prior year financial statements to conform to the current year presentation.

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 year ended December 31, 2007, we issued 750,000 shares of common stock, valued at approximately $4.6 million, in conjunction with the SGH acquisition. We also recorded in the fourth quarter of 2007, as an account receivable, a purchase price adjustment of approximately $4.2 million related to the SGH acquisition. In addition, we paid dividends to the holders of Series E and Series H Preferred Stock by issuing

81,087 shares of common stock, valued at $0.7 million. Also, as a result of the adoption of FIN 48 on January 1, 2007, our noncurrent liabilities increased by $0.5 million, our deferred tax asset increased by $0.2 million and our retained deficit increased by $0.3 million.

We also issued 250,000 shares of restricted common stock, pursuant to restricted stock awards, to our executive officers in recognition of their performance in consummating the STGC Properties acquisition and in recognition of the need to make appropriate adjustments to compensation commensurate with that currently provided to similarly situated executives in this highly competitive industry, and to provide equity incentives to those officers to remain with Crimson to maximize return to our shareholders. The restricted stock will vest over four years. In addition, we issued 2,818 restricted shares of our common stock to certain of our directors upon reelection to the board, pursuant to the director compensation plan. The stock vests on May 10, 2008. We expensed approximately $0.3 million during the year ended December 31, 2007 and will expense $1.6 million over the remaining vesting period.

During the year 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.

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 expensed $32,790 during the year ended December 31, 2007. In addition, we issued 2,410 restricted shares of our common to our directors as compensation. The stock vested on May 12, 2007. We expensed $12,742 during the year ended December 31, 2006 and expensed $7,258 during the year ended December 31, 2007.

During the year 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.

Capitalized Interest

Interest is capitalized as part of the historical cost of acquiring assets. Oil and gas investments in unproved properties and exploration and development activities which are in progress qualify for interest capitalization. Capitalized interest is calculated by multiplying the Company's weighted-average interest rate on debt by the amount of qualifying costs. Capitalized interest cannot exceed gross interest expense. As oil and gas costs excluded are transferred to the DD&A pool, any associated capitalized interest is also transferred to the DD&A pool. Capitalized interest totaled $1.3 million, $0.2 million and zero in 2007, 2006 and 2005 respectively.

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 2007, we increased our ARO to include the new wells acquired from EXCO in May 2007. 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. With the exception of leasehold improvements, which is amortized over the term of the lease, 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:

	2007	2006
Automobiles	$ 407,894	$ 328,265
Office equipment	604,670	226,456
Computer software	742,019	243,077
Leasehold improvements	581,364	—
Gathering system	271,651	271,651
Well servicing equipment	$ 103,397	$ 644,462
	2,710,995	1,713,911
Less accumulated depreciation	(913,157)	(1,096,851)
Net capitalized cost	$ 1,797,838	$ 617,060

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 based on 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 allowance 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, 2007 and 2006, 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 forfeiture 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 period shown below:

		December 31, 2005
Net loss available to common shareholders, as reported	$	(7,105,711)
Add: Total stock-based employee compensation expense included in reported net income, net of related tax effect		—
Deduct: Total stock-based employee compensation expense determined under fair value based method for all awards, net of related tax effect		(2,008,123)
Pro forma net loss available to common shareholders	$	(9,113,834)
Earnings per share:		
As reported:		
Basic	$	(2.66)
Diluted	$	(2.66)
Pro forma:		
Basic	$	(3.41)
Diluted	$	(3.41)
Weighted-average fair value per share of options granted	$	14.24

Income Taxes

We record deferred tax assets and liabilities to account for the expected future tax consequences of events that have been recognized in our financial statements and our tax returns. We routinely assess the realizability of our deferred tax assets. If we conclude that it is more likely than not that some portion or all of the deferred tax assets will not be realized under accounting standards, the tax asset is reduced by a valuation allowance. We consider future taxable income in making such assessments. Numerous judgments and assumptions are inherent in the determination of future taxable income, including factors such as future operating conditions.

Effective January 1, 2007, we adopted FASB Interpretation No. 48, *Accounting for Uncertainty in Income Taxes, an Interpretation of FASB Statement 109* (FIN 48). This statement clarifies the criteria that an individual tax position must satisfy for some or all of the benefits of that position to be recognized in a company's financial statements. FIN 48 prescribes a recognition threshold of more-likely-than-not, and a measurement attribute for all tax positions taken or expected to be taken on a tax return, in order to be recognized in the financial statements. Accordingly, we report a liability for unrecognized tax benefits resulting from uncertain tax positions taken or expected to be taken in a tax return. We recognize interest and penalties, if any, related to unrecognized tax benefits in income tax expense. See Note 8 for additional information.

Recent Accounting Pronouncements

In December 2007, the Financial Accounting Standards Board (FASB) issued a revision to SFAS No. 141 "Business Combinations" (SFAS No. 141(R)). The revision broadens the definition of a business combination to include all transactions or other events in which control of one or more businesses is obtained. Further, the statement establishes principles and requirements for how an acquirer recognizes assets acquired, liabilities assumed and any non-controlling interests acquired. SFAS No. 141(R) is effective for business combination transactions for which the acquisition date is on or after the beginning of the first reporting period beginning on or after December 15, 2008. Early adoption is prohibited. We are currently evaluating the provisions of SFAS No. 141(R) and assessing the impact it may have on us.

In February 2007, the FASB issued SFAS No. 159, “The Fair Value Option for Financial Assets and Financial Liabilities,” which permits entities to measure various financial instruments and certain other items at fair value. SFAS No. 159 will be effective for us in the first quarter of 2008. At the present time, we do not expect to apply the provisions of SFAS No. 159.

In September 2006, the FASB issued SFAS No. 157 “Fair Value Measurements.” SFAS No. 157 defines fair value, establishes a framework for measuring fair value, and expands disclosures about fair value measurements. The statement does not require any new fair value measurements for us. This statement is effective for financial statements issued for fiscal years beginning after November 15, 2007. The adoption of SFAS No. 157 is not expected to materially impact our Consolidated Financial Statements; however, it will result in additional disclosures related to the use of fair values in the financial statements.

2. Recapitalization

On April 27, 2004, we completed an $18.0 million credit agreement. 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.

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.

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.

3. Asset Retirement Obligations

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

	December 31,	
	2007	2006
Balance beginning of year	$ 4,215,205	$ 1,311,133
Accretion expense	435,328	83,807
Liabilities incurred	3,184,079	283,388
Liability settled	(279,121)	(32,049)
Revisions	—	2,568,926
Balance end of year	$ 7,555,491	$ 4,215,205

4. Accrued Expenses

Accrued expenses consisted of the following:

	December 31,	
	2007	2006
Accrued compensation	$ 1,486,116	$ 531,662
Loan fees and interest	1,530,627	148,106
Taxes	149,102	38,430
Professional fees	68,708	18,208
	$ 3,234,553	$ 736,406

5. Long-Term Debt

On May 8, 2007, the Company entered into a $400.0 million amended and restated credit agreement (the "*Senior Credit Agreement*") with Wells Fargo Bank, National Association, as agent, Wells Fargo Bank, National Association and The Royal Bank of Scotland, plc, which amended and restated the Company's existing senior secured revolving credit facility dated as of July 15, 2005, as amended. On May 8, 2007, the Company borrowed $122.7 million pursuant to the Senior Credit Agreement to pay the consideration under the EXCO Purchase Agreement (defined below) and to refinance certain existing indebtedness of the Company. On May 31, 2007, the Senior Credit Agreement was amended to provide for up to $5.0 million swing line facility.

Borrowings under the Senior Credit Agreement are subject to a borrowing base limitation based on the Company's proved oil and gas reserves. The borrowing base was reaffirmed at $200.0 million on November 1, 2007 and is subject to semi-annual redeterminations. The Senior Credit Agreement has a term of four years, and all principal amounts, together with all accrued and unpaid interest, will be due and payable in full on May 8, 2011. The Senior Credit Agreement also provides for the issuance of letters-of-credit up to a $5.0 million sub-limit.

Advances under the Senior 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" or (2) the Federal Funds rate plus a margin of 0.50%, plus a 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, two, three and nine months may be selected by the Company. A commitment fee of 0.375% on the unused portion of the borrowing base will accrue, and be payable quarterly in arrears.

In addition, on May 8, 2007, the Company entered into a five-year second lien credit agreement (the "*Second Lien Credit Agreement*") with Credit Suisse, as agent, which provides for term loans to be made to the Company in a single draw in an aggregate principal amount of $150.0 million. On May 8, 2007, the Company borrowed $150.0 million pursuant to the Second Lien Credit Agreement to pay the consideration under the EXCO Purchase Agreement (defined below) and to refinance certain existing indebtedness of the Company. The Second Lien Credit Agreement replaced the Company's existing $150.0 million subordinate credit facility, which was paid off in full and terminated at closing.

The Second Lien Credit Agreement matures on May 8, 2012. Loans under the Second Lien Credit Agreement are subject to floating rates of interest equal to, at the Company's option, the LIBOR rate plus 5.25% or the base rate plus 4.25%; however, as the Company did not obtain gross proceeds of at least $25.0 million from the issuance of Common Stock and/or preferred equity within 180 days from the closing date of the Second Lien Credit Agreement (November 5, 2007), the applicable interest rate is currently the LIBOR rate plus 5.75% or the base rate plus 4.75%. Eurodollar loans of one, two, three and six months may be selected by the Company.

The Senior Credit Agreement and the Second Lien Credit Agreement ("the *Credit Agreements*") are secured by a lien on all the assets of the Company and its active subsidiaries, as well as a security interest in the stock of all the Company's direct and indirect subsidiaries. The obligations under the Second Lien Credit Agreement will be subordinate and junior to those under the Senior Credit Agreement.

The Credit Agreements include usual and customary affirmative covenants for credit facilities of the respective types and sizes, as well as customary negative covenants, including, among others, limitations 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, as well as events of default. The Credit Agreements also contain certain financial covenants, including (a) with respect to the Senior Credit Agreement, maintaining (i) a ratio of current assets to current liabilities of at least 1.0 to 1.0, (ii) an interest coverage ratio of EBITDAX (earnings before interest, taxes, depreciation and amortization and exploration expense) to cash interest expense of 3.0 to 1.0 and (iii) a minimum leverage ratio of total debt to EBITDAX of 3.50 to 1.00 and (b) with respect to the Second Lien Credit Agreement, maintaining (i) a minimum leverage ratio of total debt to EBITDAX of 4.00 to 1.00 for the fiscal quarters ending on or before December 31, 2007, 3.50 to 1.00 for the fiscal quarters ending after December 31, 2007 and ending on or before September 30, 2008 and 3.00 to 1.00 for the fiscal quarters ending after September 30, 2008 and (ii) a PV-10 Ratio (as defined in the Second Lien Credit Agreement) less than 1.25x for a period from September 30, 2007 to December 31, 2007 and less than 1.50x for the period on or after January 1, 2008. EBITDAX is calculated without consideration of unrealized gains and losses related to stock derivatives accounted for under variable accounting rules or to commodity hedges. At December 31, 2007, we were in compliance with the aforementioned covenants.

In connection with the Credit Agreements, the Company also entered into new crude oil and natural gas hedges, which combined with the Company's existing commodity price hedge positions, result in approximately 75% of forecasted proved developed production for the Company being hedged through the end of 2011. The Company used a series of swaps and costless collars to accomplish the hedging requirements. The Company also constructively fixed the base LIBOR rate on $200.0 million of its variable rate debt through July 8, 2009 by entering into interest rate swaps at a swap price of 5.02%.

At December 31, 2007, we had $110.0 million outstanding under the Senior Credit Agreement and $150.0 million outstanding under the Second Lien Credit Agreement.

Long-term debt is as follows:

	December 31, 2007	December 31, 2006
Subordinated promissory notes to various unlocatable individuals	$ 50,000	$ 50,000
Notes payable to finance vehicles, payable in aggregate monthly installments of approximately $3,600, including interest of 5.99% to 10.49% at December 31, 2007 per annum; secured by the related equipment; due various dates through 2010	114,835	93,770
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 margin of 0.50% or, at the option of the holder, Libor plus a margin of 1.25% to 2.00% depending on the percent of the borrowing base utilized. Rate at December 31, 2006 was 8.25%	—	8,362,316
Senior Credit Agreement with a borrowing base of $200.0 million, secured by all of our assets, interest at the higher of prime or Federal Fund rate plus a margin of 0.50%, or, at the option of the holder, Libor 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, due and payable in full in May 2011	110,000,000	—
Second Lien Credit Agreement for a term loan in a single draw, secured by all of our assets, subordinate and junior to the Senior Credit Agreement, floating interest rates at Libor plus 5.75% or base rate plus 4.75%, maturing in May 2012	150,000,000	—
	260,164,835	8,506,086
Less current portion	(100,609)	(91,093)
Total long-term debt	$ 260,064,226	$ 8,414,993

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

2008	$ 100,609
2009	46,305
2010	17,921
2011	110,000,000
2012	150,000,000
	$ 260,164,835

6. Stockholders' Equity

Common Stock

	2007	2006
Par value $0.001; 200,000,000 shares authorized; 5,127,937 and 3,333,597 shares issued and outstanding as of December 31, 2007 and 2006, respectively	$ 5,128	$ 3,334

Preferred Stock

	2007	2006
Series D, par value $0.01; 12,000 shares authorized; zero and 8,000 shares issued and outstanding at December 31, 2007 and 2006, respectively The Series D preferred stock does not pay dividends and is not redeemable. The liquidation value is $500 per share. After three years from the date of issue, and thereafter, the shares are convertible to Common Stock based upon a value of $500 per Series D share divided by $80.00 per share of Common Stock..	$ —	$ 80
Series E, par value $0.01; 9,000 shares authorized; zero and 9,000 shares issued and outstanding at December 31, 2007 and 2006, respectively. The Series E pays dividends, as declared, at a rate of 2.5% per annum increasing to 6% per annum July 1, 2004, has a liquidation value of $500 per share, may be redeemed at our option and, as amended, is convertible to Common Stock based upon a value of $500 per Series E share divided by $20.00 per share of Common Stock ($9.00 per share with respect to accumulated undeclared dividends).	—	90
Series G, par value $0.01; 81,000 shares authorized; 81,000 issued and outstanding at December 31, 2007 and 2006, respectively. The Series G preferred stock pays compounded dividends, as declared, at a rate of 8% annually, has a liquidation value of $500 per share, may be redeemed at our option under certain circumstances and is convertible to Common Stock based upon a value of $500 per Series G share divided by $9.00 per share of Common Stock. We may defer dividends for the first four years and they are also convertible into our common stock at $9.00 per share	810	810
Series H, par value $0.01; 6,500 shares authorized; 5,220 and 5,250 shares issued and outstanding at December 31, 2007 and 2006, respectively. The Series H preferred stock pays dividends, as declared, at a rate of 40 common shares per preferred share per annum, has a liquidation value of $500 per share, may be redeemed at our option and is exchangeable for Common Stock based upon a value of $500 per Series H share divided by $3.50 per share of Common Stock.	22	52
	$ 832	$ $1,032

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, 2007 were

$10.2 million (Series G $10.2 million; Series H $24,559). Once dividends are declared, they may be converted to 2,286 shares of common stock (Series G 2,272; Series H 14).

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 21,000 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 125,300 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 2.6 million shares of Common Stock outstanding under the 2005 Plan. Options to purchase 1.0 million shares of Common Stock were exercisable at December 31, 2007, at exercise prices ranging from $4.50 to $18.10. At December 31, 2007, we had approximately 84,000 stock options available for grant.

Following is a schedule by year and by exercise price of the expiration of our stock options outstanding as of December 31, 2007:

	2008	**2009**	**2010**	**Thereafter**	**Total**
$4.50	77,300	20,500	17,500	—	115,300
$6.10-6.65	—	—	—	48,000	48,000
$7.15-7.90	25,000	—	—	244,700	269,700
$8.00-8.90	—	—	—	87,500	87,500
$9.70	—	—	—	360,000	360,000
$10.40	—	—	—	25,000	25,000
$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
	108,300	20,500	17,500	2,584,000	2,730,300

Pursuant to SFAS 123R for options issued under our 2005 plan, we recorded $4.2 million in expense (included in general and administrative expense on the Statement of Operations) for the year ended December 31, 2007, and estimate $8.1 million will be expensed over the remaining vesting period. We assumed a weighted average risk free interest rate of 4.12%, weighted average expected life of 7.2 years, weighted average expected volatility of 87.46% and no expected dividends.

The following table summarizes stock option activity for the three years ended December 31, 2007:

	Number of Shares Underlying Options	Weighted Average Exercise Price	Weighted Average Remaining Life (years)	Aggregate Intrinsic Value
Outstanding at December 31, 2004	194,900	6.00		
Granted	2,240,000	14.24		
Exercised	(12,500)	(4.50)		
Expired	(11,400)	(11.39)		
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		
Granted	393,000	6.86		
Exercised	(1,000)	(4.50)		
Expired	(3,500)	(7.50)		
Outstanding at December 31, 2007	2,730,300	$ 12.76	7.2	$ 15,398,892
Exercisable at December 31, 2007	1,009,950	$ 12.88	6.3	$ 5,514,327

The weighted-average grant date fair value of options granted during the years ended December 31, 2007, 2006 and 2005 was $4.53, $7.13 and $7.51, respectively. The total intrinsic value of options exercised during the years ended December 31, 2007, 2006 and 2005 was $5,425, $33,360 and $109,500, respectively.

The following table summarizes information about stock options outstanding at December 31, 2007:

Weighted Average Exercise Prices	Number Outstanding	Weighted Average Remaining Life (Years)	Number Exercisable
$4.50	115,300	1.1	115,300
$6.10-6.65	48,000	9.3	1,200
$7.15-7.90	269,700	8.7	25,630
$8.00-8.90	87,500	9.7	—
$9.70	360,000	7.2	144,000
$10.40	25,000	9.9	—
$11.60	173,300	7.3	69,320
$12.50	556,740	7.2	218,511
$17.00	1,088,760	7.2	429,989
$18.10	6,000	0.3	6,000
	2,730,300	7.2	1,009,950

The following table reflects compensation expense related to stock options (in millions, except per share data) for the years ended:

	December 31, 2007	December 31, 2006
Compensation expense related to stock options, net of tax of $1.6 million and $1.4 million, respectively	$ 2.6	$ 2.3
Basic earnings per share impact	$ (0.61)	$ (0.71)
Diluted earnings per share impact	$ (0.61)	$ (0.71)

Restricted Stock Awards

On September 28, 2007, we issued 250,000 shares of restricted common stock, pursuant to restricted stock awards, to our executive officers in recognition of their performance in consummating the STGC Properties acquisition and in recognition of the need to make appropriate adjustments to compensation commensurate with that currently provided to similarly situated executives in this highly competitive industry, and to provide equity incentives to those officers to remain with Crimson to maximize return to our shareholders. The restricted stock will vest over four years. None of the awards vested in 2007.

On May 10, 2007, we issued 2,818 restricted shares of our common stock to certain of our directors upon reelection to the board, pursuant to the director compensation plan. The stock vests on May 10, 2008. We expensed $12,796 during the year ended December 31, 2007 and will expense $7,204 over the remaining vesting period.

On May 12, 2006, we issued 2,410 restricted shares of our common stock to our directors as compensation. The stock vested on May 12, 2007. We expensed $12,742 during the year ended December 31, 2006 and expensed $7,258 during the year ended December 31, 2007.

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 expensed $32,790 during the year ended December 31, 2007.

We have not incurred any forfeitures related to the restricted stock awards issued.

Restricted stock activity for the year ended December 31, 2007 is summarized below:

	Shares	Weighted-Average Grant Date Fair Value
Non-vested as of January 1, 2007	28,644	$ 7.57
Granted	252,818	$ 7.35
Vested	(28,644)	$ 7.57
Canceled or expired	—	$ —
Non-vested as of December 31, 2007	252,818	$ 7.35

Stock Warrants

We have issued a 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:

	2007		2006		2005	
	Wtd Avg Prices	Number	Wtd Avg Prices	Number	Wtd Avg Prices	Number
Balance, January 1	$ 0.10	3,000	$ 7.40	147,000	$ 3.80	400,062
Warrants issued	—	—	—	—	0.10	5,000
Warrants exercised or expired	0.10	(3,000)	7.50	(144,000)	(1.70)	(258,062)
Balance, December 31	$ —	—	$ 0.10	3,000	$ 7.40	147,000

7. Income (Loss) Per Common Share

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

	2007	2006	2005
Net income (loss)	$ (430,517)	$ 1,858,944	$ (3,543,239)
Preferred stock dividends	(4,453,872)	(3,648,925)	(3,562,472)
Loss available to common shareholders	$ (4,884,389)	$ (1,789,981)	$ (7,105,711)
Weighted-average number of shares of Common Stock – basic (denominator)	4,330,282	3,231,000	2,673,882
Loss per share - basic	$ (1.13)	$ (0.55)	$ (2.66)
Weighted – average number of shares of Common Stock – diluted (denominator)	4,330,282	3,231,000	2,673,882
Loss per share – diluted	$ (1.13)	$ (0.55)	$ (2.66)

The numerator for basic earning per share is income (loss) available to common shareholders. The numerator for diluted earnings per share is net loss available to common shareholders in 2007, 2006 and 2005, due to antidilution.

Potential dilutive securities (vested stock options, vested stock warrants and convertible preferred stock) in 2007, 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 5,186,148 shares, 5,581,202 shares and 5,606,198 shares in 2007, 2006 and 2005, respectively.

8. Income Taxes

Income tax expense/(benefit) for 2007, 2006 and 2005 consist of the following:

	2007	2006	2005
Current tax	$ —	$ —	$ 5,974
Deferred tax expense (benefit)	(410,361)	1,425,305	(797,629)
Income tax expense (benefit)	$ (410,361)	$ 1,425,305	$ (791,655)

The following table summarizes changes in our deferred tax expense (benefit) obtained by applying a tax rate of 38% to the income (loss) before income taxes for the years ended December 31, 2007, 2006 and 2005.

	2007	2006	2005
Tax expense (benefit) calculated at statutory rate	$ (319,047)	$ 1,248,015	$ (1,647,259)
Increase (reductions) in taxes due to:			
Income tax credits	—	—	(5,974)
Effect on non-deductible expenses	35,901	(14,339)	223,918
Change in valuation allowance	—	—	582,809
Other	(127,215)	191,629	48,877
Deferred tax expense (benefit)	$ (410,361)	$ 1,425,305	$ (797,629)

As of December 31, 2007, we had net operating loss carryforwards of approximately $30.2 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,	
	2007	2006
Deferred tax assets		
Net operating loss carryforwards	$ 11,470,413	$ 8,755,256
Income tax credits	117,695	117,695
Oil and gas properties	—	—
Derivative instruments	5,973,543	—
Deferred compensation	3,175,717	1,473,526
Other	688,917	403,627
Deferred tax assets before valuation allowance	21,426,285	10,750,104
Valuation Allowance	(3,442,034)	(3,079,715)
Net deferred tax assets	17,984,251	7,670,389
Deferred tax liabilities		
Oil and gas properties	(16,361,040)	(5,683,039)
Derivative instruments	—	(937,196)
Deferred tax liabilities	(16,361,040)	(6,620,235)
Net deferred tax assets	$ 1,623,211	$ 1,050,154

Our deferred taxes increased by approximately $0.4 million during 2007. Deferred tax assets are shown net of a $3.4 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.

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 also requires expanded disclosure with respect to the uncertainty in income tax assets and liabilities. The effect of adoption of FIN 48 is required to be recognized as a change in accounting principle through a cumulative effect adjustment to retained earnings as of the beginning of the year of adoption.

We adopted the provisions of FIN 48 on January 1, 2007, which resulted in a reduction to stockholders' equity of $354,168. On the date of adoption, we had $518,219 of unrecognized tax benefits.

A reconciliation of the beginning and ending amount of unrecognized tax benefits is shown below:

		Unrecognized Tax Benefits
Balance at December 31, 2006	$	—
Adoption of FIN 48		518,219
Balance at January 1, 2007		518,219
Additions based on tax positions related to the current year		—
Additions based on tax positions related to prior years		—
Additions due to acquisition		—
Reductions due to a lapse of the applicable statute of limitations		—
Balance at December 31, 2007	$	518,219

At December 31, 2007, we had $518,219 of unrecognized tax benefits (including interest and penalties), none of which, if recognized, would affect the effective tax rate. Our policy is to recognize interest and penalties related to uncertain tax positions as income tax expense. During 2007, we recorded no potential interest expense and penalties related to unrecognized tax benefits associated with uncertain tax positions recognized in our provision for income taxes. To the extent that interest and penalties are assessed with respect to uncertain tax positions, amounts accrued will be reflected as reductions in income tax benefit.

We file a consolidated tax return in the U.S. federal jurisdiction. We are subject to U.S. federal income tax examinations for tax years beginning in 1995. The Internal Revenue Service has yet to begin an examination of our U.S. federal income tax returns for such tax years.

We also file tax returns in Colorado, Texas, Mississippi and Louisiana. These state income tax returns are generally subject to examination for a period of three to four years after filing of the respective returns. However, the state impact of any U.S. federal changes remains subject to examination by Colorado, Louisiana and Texas for a period of up to one year after formal notification to the states. The state impact of any U.S. federal changes remain subject to examination for three years after notification in Mississippi. We do not have any state audits currently underway that would have a material impact on our financial position or results of operations.

We do not anticipate that total unrecognized tax benefits will significantly change due to the settlement of audits and the expiration of statute of limitations prior to December 31, 2008. However, due to the complexity of the application of tax law and regulations, it is possible that the ultimate resolution of these positions may result in liabilities which could be materially different from these estimates.

9. 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 2007, 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, capital spending and debt service requirements.

The following derivatives were in place at December 31, 2007.

Crude Oil		**Volume/ Month**	**Price/ Unit**	**Fair Value**
Jan 2008-Dec 2008	Swap	6,500 Bbls	$76.40	$ (1,272,705)
Jan 2008-Dec 2008	Collar	18,800 Bbls	Floor $67.11-$70.50 Ceiling	(5,035,275)
Jan 2009-Dec 2009	Swap	5,200 Bbls	$74.20	(808,770)
Jan 2009-Dec 2009	Collar	12,800 Bbls	Floor $66.55-$71.40 Ceiling	(2,535,973)
Jan 2010-Dec 2010	Swap	4,250 Bbls	$72.32	(619,406)
Jan 2010-Dec 2010	Collar	9,000 Bbls	Floor $65.28-$70.60 Ceiling	(1,625,040)
Jan 2011-Dec 2011	Swap	3,300 Bbls	$70.74	(503,056)
Jan 2011-Dec 2011	Collar	7,000 Bbls	Floor $64.50-$69.50 Ceiling	(1,270,613)
Natural Gas				
Jan 2008-Dec 2008	Swap	47,000 Mmbtu	$8.97	643,221
Jan 2008-Dec 2008	Collar	659,000 Mmbtu	Floor $8.19-$9.65 Ceiling	5,439,887
Jan 2009-Dec 2009	Swap	36,000 Mmbtu	$8.32	(80,606)
Jan 2009-Dec 2009	Collar	475,000 Mmbtu	Floor $7.90-$9.45 Ceiling	(163,512)
Jan 2010-Dec 2010	Swap	29,000 Mmbtu	$7.88	(223,875)
Jan 2010-Dec 2010	Collar	351,000 Mmbtu	Floor $7.57-$9.05 Ceiling	(1,483,792)
Jan 2011-Dec 2011	Collar	266,000 Mmbtu	Floor $7.32-$8.70 Ceiling	(1,712,690)
Total fair value liability				$ (11,252,205)
Current portion				$ (430,775)
Noncurrent portion				$ (10,821,430)

We also entered into the following interest rate swap during the period:

Interest rate		Notional Amount	Fixed Rate	
Dec 8, 2007-Jul 8, 2009	Swap	$200,000,000	5.02%	
Current fair value liability				$ (2,074,476)
Noncurrent fair value liability				(1,925,589)
Net fair value liability				$ (4,000,065)

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 liability for derivative instruments at December 31, 2007 of $15.3 million and a net asset of $2.9 million at December 31, 2006. As a result of these agreements, we recorded a non-cash charge, for unsettled contracts, of $18.2 million, a non-cash increase in earnings of $6.1 million and a non-cash charge of $1.6 million for the years ended December 31, 2007, 2006 and 2005, 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 oil and gas derivatives, we realized gains, reflected as additions in oil and gas revenues, of $3.0 million for the year ended December 31, 2007 and losses, reflected as reductions in oil and gas revenues, of $0.6 million and $3.9 million for the years ended December 31, 2006 and 2005, respectively.

10. Commitments and Contingencies

	Long-term debt		Operating leases		Asset retirements		FIN 48 (1)	
2008	$	100,609	$	1,020,413	$	1,407,347	$	—
2009		46,305		650,280		365,577		—
2010		17,921		613,302		324,150		—
2011		110,000,000		551,325		537,485		—
2012		150,000,000		551,325		107,530		—
More than 5 years		—		597,269		4,813,402		—
Total	$	260,164,835	$	3,983,914	$	7,555,491	$	518,219

(1) We are unable to determine when this obligation may be required to be paid, if at all.

Lease Obligations

In 2007, we entered into various operating lease contracts for a field office trailer, vehicles, compressor units and office equipment. These contracts expire in 12 to 36 months.

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 previously leased 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 expired March 2007.

Total general and administrative rent expense for the years ended December 31, 2007, 2006 and 2005, were approximately 419,000, $184,000, and $153,000 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 20, 2008, 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 Agreements

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.

11. Acquisition of Oil and Gas Properties

In May 2007, CEO entered into the Purchase Agreement with EXCO and SGH, pursuant to which we acquired, for $285.0 million in cash (excluding adjustments) and 750,000 shares of the Company’s common stock, par value

$0.001 per share (the "*Common Stock*"), the STGC Properties held by SGH immediately before the closing of the acquisition. After considerations for typical closing adjustments, $229.0 million of the purchase price was allocated to proved properties and $28.6 million was allocated to unproved properties. EXCO acquired the properties and assets as part of a larger property package, from Anadarko Petroleum Corporation and certain of its affiliates. The properties acquired include over 200 producing wells in over 30 fields. The Company has an average 50% working interest in the properties and operates more than 80% of the value acquired. The major producing fields acquired by the Company reside in Liberty and Lavaca counties of the Upper Texas Gulf Coast, Brooks County of south Texas and Calcasieu Parish of south Louisiana. The properties and related assets were acquired through the conveyance of 100% of the membership interests of SGH from EXCO to CEO. The consolidated statements of operations include the results of operations of the STGC Properties from May 2007 to December 2007.

The unaudited pro forma results presented below for the years ended December 31, 2007 and 2006 have been prepared to give effect to the STGC Properties acquisition described above on our results of operations as if it had been consummated on January 1, 2006. The unaudited pro forma results do not purport to represent what our results of operations actually would have been if this acquisition had been completed on such date or project our results of operations for any future date or period.

	For the Years Ended December 31,	
	2007	2006
	(unaudited) (in thousands, except per share data)	
Pro forma:		
Operating revenues	$ 154,068	$ 206,909
Income from operations	$ 56,647	$ 109,677
Net income	$ 9,305	$ 60,538
Basic earnings per share	$ 1.06	$ 14.29
Diluted earnings per share	$ 0.95	$ 6.33

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:

	2007	**2006**
Unproved oil and gas properties	$ 35,059,298	$ 8,031,565
Proved oil and gas properties	361,582,956	78,404,649
Wells and related equipment and facilities	11,263,355	8,362,264
	407,905,609	94,798,478
Less accumulated depreciation, depletion and amortization	(53,214,845)	(18,868,646)
Net capitalized costs	$ 354,690,764	$ 75,929,832

The following table sets forth the composition of exploration expenses:

	2007	2006	2005(1)
Lease rental expense	$ 242,103	$ 220,110	$ —
Geological and geophysical	1,430,046	223,386	395,327
Dry holes	605,561	—	3,519,644
Abandoned property	827,380	67,999	10,552
	$ 3,105,090	$ 511,495	$ 3,925,523

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

Costs Incurred in Oil and Gas Producing Activities:

	2007	2006	2005
Property Acquisitions			
Proved	$ 238,036,360	$ —	$ 142,867
Unproved	30,407,525	8,745,363	1,244,975
Development Costs	30,814,788	6,465,719	6,171,241
Exploration Costs	13,405,017	10,783,663	3,157,841
	$ 312,663,690	$ 25,994,745	$ 10,716,924

The following table shows oil and gas property dispositions:

	2007	2006	2005
Oil and gas properties	$ —	$ —	$ 31,337
Accumulated depreciation, depletion and amortization	—	—	—
Net oil and gas properties	$ —	$ —	$ 31,337

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, 2007, 2006 and 2005, together with the changes therein. Natural gas liquids became a significant addition to our reserves since the acquisition of the STGC properties in May 2007.

	Crude Oil *(Bbls)*	Natural Gas (*Mcf*)	Natural Gas Liquids *(Bbls)*	Total (*Mcfe*)
QUANTITIES OF PROVED RESERVES:				
Balance December 31, 2004	2,963,051	29,090,277	—	48,868,583
Revisions	(78,648)	(3,025,395)	—	(3,497,283)
Extensions, discoveries and additions	—	—	—	—
Purchase	953	67,631	—	73,349
Sales	—	—	—	—
Production	(177,833)	(1,482,250)	—	(2,549,248)
Balance December 31, 2005	2,707,523	24,650,263	—	40,895,401
Revisions	(21,823)	882,566	—	751,628
Extensions, discoveries and additions	—	7,397,142	—	7,397,142
Purchase	—	—	—	—
Sales	—	—	—	—
Production	(184,881)	(1,542,423)	—	(2,651,709)
Balance December 31, 2006	2,500,819	31,387,548	—	46,392,462
Revisions (1)	(521,000)	(21,184,471)	3,692,173	(2,157,433)
Extensions, discoveries and additions	194,846	7,716,613	183,699	9,987,883
Purchase	1,137,402	82,386,946	—	89,211,358
Sales	—	—	—	—
Production	(408,864)	(9,067,777)	(285,907)	(13,236,403)
Balance December 31, 2007	2,903,203	91,238,859	3,589,965	130,197,867
PROVED DEVELOPED RESERVES:				
December 31, 2005	2,423,196	19,658,165	—	34,197,341
December 31, 2006	2,249,424	27,145,360	—	40,641,904
December 31, 2007	2,266,017	67,996,730	2,683,678	97,694,900

(1) The reporting of net NGL sales volumes began in mid-year 2007 following the close of the Exco acquisition. The end of year 2007 reserve report was updated to reflect this change in reporting. The resulting changes in volumes for natural gas and natural gas liquids are reflected in revisions.

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

	2007	2006	2005
Future cash inflows	$ 1,125,374,500	$ 313,312,927	$ 425,080,357
Future production and development costs			
Production	258,028,900	108,693,762	101,677,305
Development	65,779,100	26,229,488	27,467,896
Future cash flows before income taxes	801,566,500	178,389,677	295,935,156
Future income taxes	(198,920,968)	(43,534,046)	(91,664,228)
Future net cash flows after income taxes	602,645,532	134,855,631	204,270,928
10% annual discount for estimated timing of cash flows	(203,122,453)	(57,442,604)	(85,873,789)
Standardized measure of discounted future net cash flows	$ 399,523,079	$ 77,413,027	$ $118,397,139

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

	2007	2006	2005
Beginning of year	$ 77,413,027	$ 118,397,139	$ 83,502,377
Changes from:			
Purchases of proved reserves	324,427,750	—	230,291
Sales of producing properties	—	—	—
Extensions, discoveries and improved recovery, less related costs	43,636,200	12,096,684	—
Sales of oil and gas produced, net of production costs	(85,425,742)	(13,950,146)	(11,966,353)
Revision of quantity estimates	(15,028,200)	1,980,452	(16,437,404)
Accretion of discount	10,240,157	17,156,239	11,415,713
Change in income taxes	(88,340,375)	28,176,711	(22,544,291)
Changes in estimated future development costs	(8,693,224)	(946,764)	(6,461,166)
Development costs incurred that reduced future development costs	20,561,154	6,465,719	6,171,241
Change in sales and transfer prices, net of production costs	82,348,797	(75,110,065)	88,819,225
Changes in production rates (timing) and other	38,383,535	(16,852,942)	(14,332,494)
End of year	$ 399,523,079	$ 77,413,027	$ 118,397,139

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 $89.91 per Bbl, $6.86 per Mcf and $66.34 per Bbl; $57.67 per Bbl and $5.40 per Mcf; $57.79 per Bbl and $10.90 per Mcf, at December 31, 2007, 2006 and 2005, respectively.

13. Quarterly Results (Unaudited)

Summary data relating to the results of operations for each quarter for the years ended December 31, 2007 and 2006 follows:

	Three Months Ended			
	March 31	June 30	September 30	December 31
2007				
Net sales	$ 4,547,126	$ 26,658,550	$ 38,008,650	$ 40,328,882
Income (loss) from operations	(557,405)	9,897,272	15,672,330	8,604,102
Net income (loss) available to common shareholders	(2,458,088)	3,393,147	4,488,012	(10,307,460)
Income(loss)per common share				
Basic	$ (0.74)	$ 0.84	$ 0.93	$ (2.02)
Diluted	$ (0.74)	$ 0.45	$ 0.63	$ (2.02)
Weighted average shares outstanding				
Basic	3,333,806	4,046,510	4,827,731	5,091,206
Diluted	3,333,806	9,369,974	9,745,276	5,091,206
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

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 31, 2008, which is included in the annual report. Our audit of the basic financial statements included the financial statement schedule listed in the index appearing under Item 15(a)(2), which is the responsibility of the Company's management. In our opinion, this financial statement schedule, when considered in relation to the basic financial statements taken as a whole, presents fairly, in all material respects, the information set forth therein.

/s/ GRANT THORNTON LLP

Houston, Texas
March 31, 2008

CRIMSON EXPLORATION INC. AND SUBSIDIARIES
SCHEDULE II – VALUATION AND QUALIFYING ACCOUNTS
FOR THE YEARS ENDED DECEMBER 31, 2007, 2006 and 2005

DECRIPTION	BALANCE AT BEGINNING OF PERIOD	PROVISIONS/ ADDITIONS	RECOVERIES/ DEDUCTIONS	BALANCE AT END OF PERIOD
For the year ended December 31, 2005:				
Accounts receivable	—	30,674	—	30,674
Valuation allowance for deferred tax assets	$ 2,496,906	582,809	—	3,079,715
For the year ended December 31, 2006				
Accounts receivable	$ 30,674	$ 87,436	$ —	$ 118,110
Valuation allowance for deferred tax assets	$ 3,079,715	$ —	$ —	$ 3,079,715
For the year ended December 31, 2007:				
Accounts receivable	$ 118,110	$ 96,905	$ —	$ 215,015
Valuation allowance for deferred tax assets	$ 3,079,715	$ 362,319	$ —	$ 3,442,034