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

FORM 10-K

☒ ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
For the fiscal year ended December 31, 2010
OR
☐ TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934

Commission file number: 001-12108

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**
(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 ☐ (Do not check if smaller reporting company) Smaller reporting company ☒

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

As of June 30, 2010, the aggregate market value of the registrant's common stock held by non-affiliates of the registrant was $58,284,720 based on the closing sales price of $2.67 of the Registrant's 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 9, 2011, there were 45,203,278 shares of common stock outstanding.

DOCUMENTS INCORPORATED BY REFERENCE

Portions of our Definitive Proxy Statement for the 2011 Annual Meeting, expected to be filed within 120 days of our fiscal year end, are incorporated by reference into Part III.

CAUTIONARY STATEMENT CONCERNING FORWARD-LOOKING STATEMENTS

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

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

- estimates of proved reserve quantities and net present values of those reserves;
- reserve potential;
- business strategy;
- estimates of future commodity prices;
- amounts, timing and types of capital expenditures and operating expenses;
- expansion and growth of our business and operations;
- expansion and development trends of the oil and gas industry;
- acquisitions of natural gas and crude oil properties;
- production of crude oil and natural gas reserves;
- exploration prospects;
- wells to be drilled and drilling results;
- operating results and working capital;
- results of borrowing base redeterminations under our revolving credit facility;
- future methods and types of financing; and
- the risks described elsewhere in this Annual Report and in the documents incorporated by reference herein.

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 caution that a number of factors could cause future production, revenues and expenses to differ materially from our expectations. 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 provided 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. For a discussion of risk factors affecting our business, see "Risk Factors."

PART I

ITEM 1. Business

Company Overview

Crimson is an independent energy company engaged in the acquisition, exploitation, exploration and development of natural gas and crude oil properties. We have historically focused our operations in the onshore U.S. Gulf Coast and South Texas regions, which are generally characterized by high rates of return in known, prolific producing trends. We have recently expanded our strategic focus to include longer reserve life resource plays that we believe provide significant long-term growth potential in multiple formations.

We intend to grow reserves and production by developing our existing producing property base, developing our East Texas and South Texas resource potential, and pursuing opportunistic acquisitions in areas where we have specific operating expertise. We have developed a significant project inventory associated with our existing property base. Our technical team has a successful track record of adding reserves through the drillbit. Since January 2008 and through December 2010, we have drilled 42 gross (19.0 net) wells with an overall success rate of 93%. At December 31, 2010, we had two wells in progress.

As of December 31, 2010, our proved reserves, as estimated by our independent reserve engineering firm, Netherland, Sewell & Associates, Inc., in accordance with reserve reporting guidelines mandated by the SEC, were 166.5 Bcfe, consisting of 135.7 Bcf of natural gas and 5.1 MMBbl of crude oil, condensate and natural gas liquids, with a PV-10 of $239.7 million. As of December 31, 2010, 81% of our proved reserves were natural gas, 48% were proved developed and 89% were attributed to wells and properties operated by us. During 2010 we grew proved reserves from 97.5 Bcfe at December 31, 2009 to 166.5 Bcfe at December 31, 2010.

Our areas of primary focus include the following:

- *Southeast Texas.* Our Southeast Texas region includes approximately 25,900 gross (14,600 net) acres in the Felicia field area in Liberty County, and in Madison and Grimes Counties. As of December 31, 2010, we owned 72 gross (38.8 net) producing wells producing mostly from the Yegua, Georgetown and Cook Mountain formations. Our 2011 capital budget includes 5 gross (3.5 net) wells in this region, three in Liberty County, as well as initial wells targeting the Woodbine and Georgetown horizontal oil plays in Madison County.

- *South Texas.* Our South Texas region includes approximately 13,000 (6,150 net) acres in Karnes, Zavala and Dimmitt Counties that is held by production and which we believe to be prospective in the oil-weighted sections of the Eagle Ford Shale in those counties. Our South Texas region also includes approximately 2,800 gross (560 net) acres in Bee County, which we believe to be prospective in the Austin Chalk and gas/condensate section of the Eagle Ford Shale. We also have approximately 89,300 gross (51,300 net) acres predominantly in Brooks, Lavaca, DeWitt, Zapata, Webb and Matagorda Counties that are prospective for conventional drilling. During the third quarter of 2010, our industry partner successfully drilled two wells in Bee County confirming the existence of the Eagle Ford gas/condensate window and these wells commenced production in January 2011. As of December 31, 2010, we owned 280 gross conventional (146.3 net) producing wells in the South Texas region producing from the Wilcox, Frio and Vicksburg formations, as well as others. Our 2011 capital budget includes plans to drill three gross (1.2 net) wells in this region; one gross (0.2 net) in Bee County, one gross (0.5 net) in Zavala County and one gross (0.5 net) in Karnes County targeting the Eagle Ford oil section.

  East Texas. Our East Texas region includes approximately 18,200 gross (12,700 net) acres acquired in 2008 and 2009 in the highly prospective gas resource play in San Augustine and Sabine Counties, where we are focusing primarily on the pursuit of the Haynesville Shale, Mid-Bossier Shale and James Lime formations. In November 2009, we announced the completion and initial production of our first well on this acreage, the Kardell #1H, with the horizontal completion in the Haynesville Shale formation. In 2010, we began the operated phase of our drilling program in East Texas with our

Grizzly #1 well which we completed in the Mid-Bossier formation and which began commercial production in August 2010. We then completed our Gobi #1H well in the Mid-Bossier and it commenced production.in November 2010. All three of these wells are in our Bruin Prospect Area in San Augustine County. At the end of February 2011 we completed the Bengal #1H, which is the first well in our Tiger Prospect Area in Sabine County, Texas and it is currently being put on production. We also participated, on a non-operated basis, in the drilling of the first well in our Fairway Farms Prospect Area, the Halbert Trust GU #1, a Mid-Bossier completion that commenced production in December 2010. Our 2011 capital budget currently includes a total of 4 gross (2.2 net) wells in East Texas, three in our Bruin Prospect Area and one in our Bulldog Prospect Area. We anticipate that we will ultimately preserve between 4,000 and 6,000 net acres in East Texas by 2012 through drilling or lease extensions.

We also own interests in the following areas:

- *Colorado and Other.* This region includes approximately 16,900 gross (11,800 net) acres in the Denver Julesburg Basin in Colorado (mostly in Adams and Weld Counties), minor non-operating working interests in the Fenton field area of Calcasieu Parish, Louisiana and a minor crude oil property in Mississippi. There has been a recent surge in activity in the area of our Colorado properties in pursuit of the Niobrara oil formation. The vast majority of our acreage in this area is held by production, so we have the flexibility to monitor the activity, and results, of our industry peers in the Niobrara to develop our exploitation strategy. We currently plan to drill one gross (0.7 net) well in the Niobrara in 2011.

The following table sets forth certain information with respect to our proved reserves as of December 31, 2010, as estimated by Netherland, Sewell & Associates, Inc., and net production and net acreage for the twelve months ended December 31, 2010. The following table also identifies potential drilling locations as of December 31, 2010:

Region	Estimated Proved Reserves as of December 31, 2010 (MMcfe)	% Natural Gas	% Proved Developed	Average Daily Production for the Twelve Months Ended December 31, 2010 (Mcfe/d)	Net acreage at December 31, 2010	Identified Potential Gross Drilling Locations at December 31, 2010(1) (2)
Southeast Texas	28,262	57%	86%	18,560	14,600	65
South Texas	71,024	77%	58%	12,880	51,300	359
East Texas(3)	59,336	100%	16%	2,677	12,800	245
Colorado and Other	7,876	72%	64%	1,295	12,400	191
Total	166,498	81%	48%	35,412	91,100	860

(1) Includes multiple drilling locations on acreage with multiple target formations.

(2) Includes 178 drilling locations on our resource play acreage in South Texas. Due to the nature of the acreage, these reserves and potential drilling locations may not all eventually be operated by us. See “Risk Factors— Many of our East Texas leases are not producing and must be drilled before expiration, generally within three years, in order to hold the leases by production, or they will terminate.”

(3) All drilling locations are on resource play acreage. In the highly competitive market for Haynesville Shale acreage, failure to drill sufficient wells timely to hold this acreage will result in a substantial renewal cost, or if renewal is not feasible, loss of lease investment and prospective drilling opportunities in the Haynesville Shale, as well as in the Mid-Bossier Shale, James Lime, Pettet and Knowles Lime formations. Drilling locations in this region were identified assuming between 4,000 and 6,000 net acres are held through drilling or lease extensions and an allocated 80 acres per potential horizontal East Texas well drilled to multiple target formations.

We have significantly increased our proved reserves and production through acquisitions since our recapitalization in early 2005. In 2007, we tripled our reserve size through the acquisition from EXCO Resources, Inc. (*"EXCO"*) of producing properties in the South Texas, Southeast Texas and Southwest Louisiana regions, adding an aggregate of approximately 95 Bcfe to our net proved reserves at a cost of $2.50 per Mcfe of proved reserves as of the effective date. We also added 21 Bcfe to our South Texas proved reserves through the Smith Production Inc. (*"Smith"*) acquisition in 2008 at an average cost of $2.82 per Mcfe of proved reserves as of the closing date. Our acquisitions are typically focused on areas in which we can leverage our geographic and geological expertise to exploit those drilling opportunities identified at the time of the acquisition and develop an inventory of additional drilling prospects that we believe will enable us to grow production and add reserves. We intend to continue to pursue the acquisition of assets in our core areas, to continue to selectively expand our presence and exploit our positions in our East Texas and South Texas resource plays and to continue to develop exploratory opportunities through our internal prospect generation team.

During 2008 and 2009, we acquired approximately 12,700 net acres in San Augustine and Sabine Counties in East Texas, which we have proved to be prospective in the Haynesville Shale, Mid-Bossier, and James Lime formations. Recent activity in the area indicates that the Pettet and Knowles Lime formations also appear prospective. We have separated our acreage into several joint development areas (*"JDAs"*) of varying sizes and are working with other industry players holding acreage positions in those areas to jointly develop our positions. We believe that we will ultimately be able to preserve between 4,000 and 6,000 net acres in this play through drilling, re-leasing or obtaining lease extensions. We have successfully drilled five (100% success rate) wells on our East Texas acreage and currently have two awaiting completion and one being placed on production.

Offices

We currently lease and sublease, through January 31, 2014, 54,939 square feet of executive and corporate office space located at 717 Texas Avenue in downtown Houston, Texas. Rent, including parking and net of sublease rent, related to this office space for the twelve months ended December 31, 2010 was approximately $1.1 million. Effective January 1, 2010, we subleased to a subtenant 27,144 square feet of this space for a total rental of approximately $86,000 per month through September 30, 2011.

Strategy

The key elements of our business strategy are:

- *Enhance our portfolio by shifting capital to our oil and liquids rich opportunities.* During 2011 we will pursue a balanced drilling program that is designed to validate our multiple oil and liquids rich opportunities in proven, active areas, while continuing to preserve only the highest-potential, concentrated portions of our acreage position in the East Texas Haynesville/Mid-Bossier/James Lime play. We made the decision to allocate a much larger portion of our 2011 capital budget to the oil-weighted opportunities due to superior current economics, the weakness of the natural gas market and the difficulty in consolidating drilling units in the East Texas gas play prior to lease expirations due to the shift in focus of the other operators in the area to oil weighted projects.

- *Exploit our existing producing conventional property base to generate cash flows.* We believe our multi-year drilling inventory of high return exploitation opportunities on our existing producing properties provides us with a solid platform to continue growing our reserves and production for the next several years. We believe these projects, if successful, will allow us to fund a substantial portion of our resource play activity from cash flows from operations. We are currently focusing much of our exploitation drilling on our Liberty County acreage, located in Southeast Texas. We will be targeting the Yegua and Cook Mountain formations in which we and other industry players have experienced consistent success in the area. We own 3D seismic data that covers substantially all of our Liberty County acreage, giving us a higher degree of confidence in the potential in this area. During 2010, our Liberty County program produced three successful wells and one successful recompletion. Our 2011 capital program includes three wells in Liberty County.

- *Develop our East Texas resource play.* We continue to attempt to preserve as much of our 12,700 net acre position in East Texas as logistically and economically feasible, i.e., through a combination of drilling, re-leasing or extending expiring leases. Our efforts are currently focused primarily on our Bruin, Tiger and Fairway Farms Prospect Areas in San Augustine and Sabine Counties through 2011, with full development in multiple formations to be pursued in the following years depending upon market economics, capital availability and success rate. During 2011, we expect to drill 4.0 gross (2.2 net) wells that target the Haynesville and Mid-Bossier Shales, while retaining future development opportunities in shallower formations. We believe we will be able to preserve between 4,000 and 6,000 net acres of our 12,700 position through drilling, re-leasing or extending expiring leases. After we complete the drilling planned for 2011 and early 2012, to preserve this acreage, we will allocate additional drilling capital to this area when drilling economies improve.

- *Develop our South Texas resource play.* Pursuant to its participation agreement with us, our industry partner successfully drilled two horizontal wells on our position in Bee County during 2010 proving the prospectivety of the Eagle Ford Shale on our acreage. During 2011, we expect to drill initial wells in our held-by-production areas in both of our Karnes and Zavala County areas, targeting the Eagle Ford oil window, and a third well in Bee County. We plan to allocate substantial capital over the next several years to develop the oil and natural gas liquids resource we believe exists on our South Texas acreage.

- *Pursue the developing Woodbine/Georgetown horizontal oil play in our Madisonville Field in Madison County, Texas.* We have approximately 5,000 net acres in Madison and Grimes counties from which we have historically focused primarily on maximizing production from producing conventional wells. Recent horizontal drilling for oil in the Woodbine and Georgetown formations, adjacent to our acreage, has been very successful. Based on those results, we believe that portions of our asset base in the area are prospective for the Woodbine and Georgetown. We currently plan to drill two wells on our acreage during 2011 to validate this belief.

- *Colorado Niobrara Shale.* Our activities here have historically been limited to the production of small amounts of oil and gas from the D & J Sands in Weld and Adams Counties. Recent industry activity in the area has proven that the application of horizontal drilling technology for oil in the shallower Niobrara Shale provides tremendous return possibilities. We believe that the Niobrara is prospective in parts of our acreage and will likely drill one well on our acreage in 2011 to validate that belief.

- *Explore in defined producing trends.* Our exploration activities consist primarily of step-out drilling in known, producing formations in our legacy areas of South and Southeast Texas and Colorado. In 2007, we began acquiring seismic data to use in identifying new exploration prospects. Currently, we have a library of over 4,200 square miles of 3D seismic data and over 2,500 linear miles of 2D seismic data.

- *Make opportunistic acquisitions that meet our strategic and financial objectives.* We intend to continue evaluating opportunistic acquisitions of natural gas and crude oil properties, including both undeveloped and developed reserves in areas where we currently have a presence and specific operating expertise.

- *Reduce commodity price exposure through hedging.* We employ the use of swaps and costless collar derivative instruments to limit our exposure to commodity prices. We currently have 12.5 Bcfe of equivalent production hedged for 2011 and 2012, consisting of 6.0 Bcf of natural gas hedges, 225.8 MBbl of crude oil hedges and 2.1 million gallons of natural gas liquids hedges in place for 2011, at average floor prices of $6.31/MMBtu, $77.83/Bbl and $7.32/gallon, respectively and 3.8 Bcf of natural gas hedges and 175.2 MBbl of crude oil hedges in place for 2012 at average floor prices of $5.00/MMBTU and $84.99/Bbl, respectively.

Our Employees

On March 9, 2011, we had 63 full time employees, of which 19 were field personnel. We have been able to attract a talented team of industry professionals from our industry peers that have been successful in achieving significant growth and success in the past. As such, we are well-positioned to adequately manage and develop our existing assets and also to increase our proved reserves and production through exploitation and exploration drilling. None of our employees are covered by collective bargaining agreements. We believe our relationship with our employees is good.

Government Regulation and Industry Matters

Federal and State Regulatory Requirements

We are a public company subject to the rules and regulations of the Securities and Exchange Commission (*"SEC"*). These rules and regulations 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 rules and regulations 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 release 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 current or 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 or reinterpreted, and any such changes or interpretations could have an adverse effect on our business.

Industry Regulations

The availability of a ready market for natural gas, crude oil and natural gas liquids production depends upon numerous factors beyond our control. These factors include regulation of natural gas, crude oil and natural gas liquids production, federal and state regulations governing environmental quality and pollution control, state limits on allowable rates of production by well or proration unit, the amount of natural gas, crude oil and natural gas liquids available for sale, the availability of adequate pipeline and other transportation and processing facilities and the marketing of competitive fuels. For example, a productive natural gas well may be "shut-in" because of an oversupply of natural gas or lack of an available natural gas pipeline in the areas in which we may conduct operations. State and federal regulations generally are intended to prevent waste of natural gas, crude oil and natural gas liquids, protect rights to produce natural gas, crude oil and natural gas liquids between owners in a common reservoir, control the amount of natural gas, crude oil and natural gas liquids produced by assigning allowable rates of production and control contamination of the environment. Pipelines are subject to the jurisdiction of various federal, state and local agencies. We are also subject to changing and extensive tax laws, the effects of which cannot be predicted. The following discussion summarizes the regulation of the United States oil and gas industry. We believe that we are in substantial compliance with the various statutes, rules, regulations and governmental orders to which our operations may be subject, although there can be no assurance that this is or will remain the case. Moreover, such statutes, rules, regulations and government orders may be changed or reinterpreted from time to time in response to economic or political conditions, and there can be no assurance that such changes or reinterpretations will not materially adversely affect our results of operations and financial condition. The following discussion is not intended to constitute a complete discussion of the various statutes, rules, regulations and governmental orders to which our operations may be subject.

Regulation of Natural Gas, Crude Oil and Natural Gas Liquids Exploration and Production

Our operations are subject to various types of regulation at the federal, state and local levels. Such regulation includes requiring permits for the drilling of wells, maintaining bonding requirements in order to drill or operate wells and regulating the location of wells, the method of drilling and casing wells, the surface use and restoration of properties upon which wells are drilled, the plugging and abandoning of wells and the disposal of fluids used in connection with operations. Our operations are also subject to various conservation laws and regulations. These include the regulation of the size of drilling and spacing units or proration units and the density of wells that may be drilled in and the unitization or pooling of crude oil and natural gas properties. In this regard, some states allow the forced pooling or integration of tracts to facilitate exploration while other states rely primarily or exclusively on voluntary pooling of lands and leases. In areas where pooling is voluntary, it may be more difficult to form units, and therefore more difficult to develop a project, if the operator owns less than 100% of the leasehold. In addition, state conservation laws which establish maximum rates of production from crude oil and natural gas wells, generally prohibit the venting or flaring of natural gas and impose certain requirements regarding the ratability of production. The effect of these regulations may limit the amount of natural gas, crude oil and natural gas liquids we can produce from our wells and may limit the number of wells or the locations at which we can drill. The regulatory burden on the oil and gas industry increases our costs of doing business and, consequently, affects our profitability. Inasmuch as such laws and regulations are frequently expanded, amended and interpreted, we are unable to predict the future cost or impact of complying with such regulations.

Regulation of Sales and Transportation of Natural Gas

Federal legislation and regulatory controls have historically affected the price of natural gas produced by us, and the manner in which such production is transported and marketed. Under the Natural Gas Act of 1938, or NGA, the Federal Energy Regulatory Commission, or the FERC, regulates the interstate transportation and the sale in interstate commerce for resale of natural gas. Effective January 1, 1993, the Natural Gas Wellhead Decontrol Act, or the Decontrol Act, deregulated natural gas prices for all "first sales" of natural gas, including all sales by us of our own production. As a result, all of our domestically produced natural gas may now be sold at market prices, subject to the terms of any private contracts that may be in effect. However, the Decontrol Act did not affect the FERC's jurisdiction over natural gas transportation.

Under the provisions of the Energy Policy Act of 2005, or the 2005 Act, the NGA has been amended to prohibit market manipulation by any person, including marketers, in connection with the purchase or sale of natural gas, and the FERC has issued regulations to implement this prohibition. The Commodity Futures Trading Commission, or CFTC, also holds authority to monitor certain segments of the physical and futures energy commodities market including oil and natural gas. With regard to physical purchases and sales of natural gas and other energy commodities, and any related hedging activities that we undertake, we are thus required to observe anti-market manipulation laws and related regulations enforced by FERC and/or the CFTC. These agencies hold substantial enforcement authority, including the ability to assess civil penalties of up to $1 million per day per violation.

Under the 2005 Act, the FERC has also established regulations that are intended to increase natural gas pricing transparency through, among other things, new reporting requirements and expanded dissemination of information about the availability and prices of gas sold. To the extent that we enter into transportation contracts with interstate pipelines that are subject to FERC regulation, we are subject to FERC requirements related to use of such interstate capacity. Any failure on our part to comply with the FERC's regulations or an interstate pipeline's tariff could result in the imposition of civil and criminal penalties.

Our natural gas sales are affected by intrastate and interstate gas transportation regulation. Following the Congressional passage of the Natural Gas Policy Act of 1978, or the NGPA, the FERC adopted a series of regulatory changes that have significantly altered the transportation and marketing of natural gas. Beginning with the adoption of Order No. 436, issued in October 1985, the FERC has implemented a series of major restructuring orders that have required pipelines, among other things, to perform "open access" transportation of gas for others, "unbundle" their sales and transportation functions, and allow shippers to release their unneeded capacity temporarily and permanently to other shippers. As a result of these changes, sellers and buyers of gas have gained direct access to the particular pipeline services they need and are better able to conduct business with a larger number of counterparties. We believe these changes generally have improved our access to markets while, at the same time, substantially increasing competition in the natural gas marketplace. It remains to be seen, however, what effect the FERC's other activities will have on access to markets, the fostering of competition and the cost of doing business. We cannot predict what new or different regulations the FERC and other regulatory agencies may adopt, or what effect subsequent regulations may have on our activities. We do not believe that we will be affected by any such new or different regulations materially differently than any other seller of natural gas with which we compete.

In the past, Congress has been very active in the area of gas regulation. However, as discussed above, the more recent trend has been in favor of deregulation, or "lighter handed" regulation, and the promotion of competition in the gas industry. There regularly are other legislative proposals pending in the federal and state legislatures that, if enacted, would significantly affect the petroleum industry. At the present time, it is impossible to predict what proposals, if any, might actually be enacted by Congress or the various state legislatures and what effect, if any, such proposals might have on us. Similarly, and despite the trend toward federal deregulation of the natural gas industry, we cannot predict whether or to what extent that trend will continue, or what the ultimate effect will be on our sales of gas. Again, we do not believe that we will be affected by any such new legislative proposals materially differently than any other seller of natural gas with which we compete.

Oil Price Controls and Transportation Rates

Sales prices of crude oil, condensate and gas liquids by us are not currently regulated and are made at market prices. Our sales of these commodities are, however, subject to laws and to regulations issued by the Federal Trade Commission, or the FTC, prohibiting manipulative or fraudulent conduct in the wholesale petroleum market. The FTC holds substantial enforcement authority under these regulations, including the ability to assess civil penalties of up to $1 million per day per violation. Our sales of these commodities, and any related hedging activities, are also subject to CFTC oversight as discussed above.

The price we receive from the sale of these products may be affected by the cost of transporting the products to market. Much of the transportation is through interstate common carrier pipelines. Effective as of January 1, 1995, the FERC implemented regulations generally grandfathering all previously approved interstate transportation rates and establishing an indexing system for those rates by which adjustments are made annually based on the rate of inflation, subject to certain conditions and limitations. The FERC's regulation of crude oil transportation rates may tend to increase the cost of transporting crude oil and natural gas liquids by interstate pipelines, although the annual adjustments may result in decreased rates in a given year. Every five years, the FERC must examine the relationship between the annual change in the applicable index and the actual cost changes experienced in the oil pipeline industry. In March 2006, to implement the second of the required five-yearly re-determinations, the FERC established an upward adjustment in the index to track oil pipeline cost changes. The FERC determined that the Producer Price Index for Finished Goods plus 1.3 percent (PPI plus 1.3 percent) should be the oil pricing index for the five-year period beginning July 1, 2006. We are not able at this time to predict the effects of these regulations or FERC proceedings, if any, on the transportation costs associated with crude oil production from our crude oil producing operations.

Environmental Regulations

Various federal, state and local authorities regulate our operations with regard to air and water quality, release of substances and other environmental matters. These laws and regulations may require the acquisition of a permit before drilling commences, restrict the types, quantities and concentration of various substances that can be released into the environment in connection with drilling and production activities, limit or prohibit drilling activities on certain lands within wilderness, wetlands and other protected areas, require remedial measures to mitigate pollution from current or former operations, such as pit closure and plugging abandoned wells, and impose substantial liabilities for pollution resulting from production and drilling operations. In addition, various laws and regulations require that inactive well, pipeline, and facility sites be abandoned and reclaimed. Public interest in the protection of the environment has increased dramatically in recent years. The trend of more expansive and stringent environmental legislation and regulations applied to the crude oil and natural gas industry could continue, resulting in increased costs of doing business and consequently affecting profitability. To the extent laws are enacted or other governmental action is taken that further restricts drilling or imposes more stringent and costly operating, waste handling, disposal and cleanup requirements, our business and prospects could be adversely affected.

The Comprehensive Environmental Response, Compensation and Liability Act, also known as "CERCLA" or the "Superfund" law, and similar state laws impose liability, without regard to fault or the legality of the original conduct, on certain classes of potentially responsible persons that are considered to have contributed to the release of a "hazardous substance" into the environment. These potentially responsible persons include the owner or operator of the disposal site or sites where the release occurred and companies that disposed or arranged for the disposal of the hazardous substances found at the site. Persons who are or were responsible for releases of hazardous substances under CERCLA may be subject to joint and several liability for the costs of cleaning up the hazardous substances that have been released into the environment, for damages to natural resources and for the costs of certain health studies, and it is not uncommon for neighboring landowners and other third parties to file claims for personal injury and property damage allegedly caused by the hazardous substances released into the environment. We generate materials in the course of our operations that may be regulated as hazardous substances.

We generate wastes that may be subject to the federal Resource Conservation and Recovery Act or the RCRA, and comparable state statutes. The U.S. Environmental Protection Agency, or the EPA, and various state agencies have limited the approved methods of disposal for certain hazardous and nonhazardous wastes. Furthermore, certain wastes generated by our crude oil and natural gas operations that are currently exempt from regulation as "hazardous wastes" may in the future be designated as "hazardous wastes," and therefore be subject to more rigorous and costly operating and disposal requirements.

We currently own or lease numerous properties that for many years have been used for the exploration and production of crude oil and natural gas. Although we believe that we have used good operating and waste disposal practices that were standard in the industry at the time, petroleum hydrocarbons or wastes may have been disposed of or released on or under the properties owned or leased by us or on or under locations where such wastes have been taken for recycling or disposal. In addition, many of these properties have been operated by third parties whose treatment and disposal or release of petroleum hydrocarbons or wastes was not under our control. These properties and the wastes disposed thereon may be subject to the CERCLA, RCRA and analogous state laws as well as state laws governing the management of crude oil and natural gas wastes. Under such laws, which may impose strict, joint and several liability, we could be required to remove or remediate previously disposed wastes (including wastes disposed of or released by prior owners or operators) or property contamination (including groundwater contamination) or to perform remedial plugging operations to prevent future contamination.

Our operations may be subject to the Clean Air Act, or the CAA, and comparable state and local requirements. Amendments to the CAA adopted in 1990 contain provisions that have resulted in the gradual imposition of pollution control requirements with respect to air emissions from our operations. The EPA and states have developed, and continue to develop, regulations to implement these requirements. While we may be required to incur capital expenditures in the next several years for air pollution control equipment in connection with maintaining or obtaining operating permits and approvals addressing air emission-related issues, we do not believe that our operations will be materially adversely affected by any such requirements.

In response to certain scientific studies suggesting that emissions of certain gases, commonly referred to as greenhouse gases, or "GHGs," and including carbon dioxide and methane, are contributing to the warming of the Earth's atmosphere and other climatic conditions. The EPA made findings in December 2009 that emissions of GHGs present an endangerment to public health and the environment. Based on these findings, the EPA has adopted and implemented two sets of regulations under the CAA that would restrict emissions of GHGs under existing provisions of the CAA. The first regulation limits emissions of GHGs from motor vehicles and the second one that regulates emissions of GHGs from certain large stationary sources under the Prevention of Significant Deterioration, or "PSD," and Title V permitting programs, effective January 2, 2011. This stationary source rule "tailors" these permitting programs to apply to certain stationary sources of GHG emissions in a multi-step process, with the largest sources first subject to permitting. Facilities required to obtain PSD permits for their GHG emissions also will be required to reduce those emissions according to "best available control technology" standards for GHG will be established by the states or, in some instances, by the EPA on a case-by-case basis. The EPA's rules relating to emissions of GHGs from large stationary sources of emissions are currently subject to a number of legal challenges but the federal courts have thus far declined to issue any injunctions to prevent EPA from implementing or requiring state environmental agencies to implement the rules. In addition, in November 2010, the EPA expanded its existing GHG reporting rule to include onshore oil and natural gas production, processing, transmission, storage, and distribution facilities, beginning in 2012 for emissions occurring in 2011.

In addition, from time to time Congress has considered legislation to reduce emissions of GHGs, and almost one-half of the states have already taken legal measures to reduce emissions of GHGs, primarily through the planned development of GHG emission inventories and/or regional GHG cap and trade programs. Most of these cap and trade programs work by requiring either major sources of emissions or major producers of fuels to acquire and surrender emission allowances, with the number of allowances available for purchase reduced each year until the overall GHG emission reduction goal is achieved. These allowances would be expected to escalate significantly in cost over time. Although it is not possible at this time to predict when Congress may pass climate change legislation, any future federal laws that may be adopted to address GHG emissions could require us to incur increased operating costs and could adversely affect demand for the oil and natural gas we produce.

Finally, it should be noted that some scientists have concluded that increasing concentrations of greenhouse gases in the Earth's atmosphere may produce climate changes that have significant physical effects, such as increased frequency and severity of storms, droughts, and floods and other climatic events. If any such effects were to occur, they could have in adverse effect on our assets and operations.

The Federal Water Pollution Control Act, also known as the "Clean Water Act," and analogous state laws impose restrictions and strict controls regarding the discharge of pollutants into navigable waters. Pursuant to the Clean Water Act and analogous state laws, permits must be obtained to discharge pollutants into state waters or waters of the United States. Any such discharge of pollutants into regulated waters must be performed in accordance with the terms of the permit issued by the EPA or the analogous state agency. Spill prevention, control and countermeasure, or "SPCC" plan requirements under federal law require appropriate containment berms and similar structures to help prevent the contamination of navigable waters in the event of a petroleum hydrocarbon tank spill, rupture or leak. In addition, the Clean Water Act and analogous state laws require individual permits or coverage under general permits for discharges of storm water runoff from certain types of facilities. It is customary to recover natural gas from deep shale formations through the use of hydraulic fracturing, combined with sophisticated horizontal drilling. Hydraulic fracturing involves the injection of water, sand and chemical additives under pressure into rock formations to stimulate gas production. The process is typically regulated by state oil and gas commissions. However, the EPA recently asserted federal regulatory authority over hydraulic fracturing involving diesel additives under the federal Safe Drinking Water Act's Underground Injection Program. While the EPA has yet to take any action to enforce or implement this newly asserted regulatory authority, industry groups have filed suit challenging the EPA's recent decision. At the same time, the EPA has commenced a comprehensive research study on the potential adverse impacts that hydraulic fracturing may have on water quality and public health with results of the study expected to be available in late 2012, and a committee of the U.S. House of Representatives is conducting an investigation of hydraulic fracturing practices. In addition, legislation was proposed in the recently completed session of Congress to provide for federal regulation of hydraulic fracturing and to require disclosure of the chemicals used in the fracturing process, and such legislation could be introduced and adopted in the current session of Congress. Also, some states and local governments are considering increased regulatory oversight of hydraulic fracturing through additional permit requirements, operational restrictions and temporary or permanent bans on hydraulic fracturing in certain environmentally-sensitive areas such as watersheds. The adoption of any federal or state legislation or implementing regulations imposing limitations on the hydraulic fracturing process could lead to operational delays or increased operating costs.

The Oil Pollution Act of 1990, or the "OPA," contains numerous requirements relating to the prevention of and response to oil spills into waters of the United States. The OPA subjects owners of facilities to strict, joint and several liability for all containment and cleanup costs and certain other damages arising from a spill, including, but not limited to, the costs of responding to a release of oil to surface waters. Noncompliance with OPA may result in varying civil and criminal penalties and liabilities.

We are subject to a number of federal and state laws and regulations, including the federal Occupational Safety and Health Act, or the "OSHA," and comparable state statutes, whose purpose is to protect the health and safety of workers. In addition, the OSHA hazard communication standard, the EPA community right-to-know regulations under Title III of the federal Superfund Amendment and Reauthorization Act and comparable state statutes require that information be maintained concerning hazardous materials used or produced in our operations and that this information be provided to employees, state and local government authorities and citizens. We believe that we are in substantial compliance with all applicable laws and regulations relating to worker health and safety.

Title to Properties

We believe we have satisfactory title to all of our producing properties in accordance with standards generally accepted in the oil and gas industry. Our properties are subject to customary royalty interests, liens incident to operating agreements, liens for current taxes and other burdens, which we believe do not materially interfere with the use of or affect the value of such properties. As is customary in the industry in the case of undeveloped properties, little investigation of record title is made at the time of acquisition (other than a preliminary review of local records). Detailed investigations, including a title opinion rendered by a licensed attorney, are typically made before commencement of drilling operations.

We have granted mortgage liens on substantially all of our natural gas and crude oil properties to secure our revolving credit agreement and second lien credit agreement. These mortgages and the credit agreements contain substantial restrictions and operating covenants that are customarily found in credit agreements of this type. See Note 9 — "Debt" for further information.

Marketing

We sell a significant portion of our natural gas production to purchasers pursuant to sales agreements which contain a primary term of up to two years and crude oil production to purchasers under sales agreements with primary terms of up to one year. The sales prices for natural gas are tied to industry standard published index prices, subject to negotiated price adjustments, while the sale prices for crude oil are tied to industry standard posted prices subject to negotiated price adjustments.

Our purchasers are engaged in the natural gas and crude oil business throughout the world. Historically, we have been dependent upon a few purchasers for a significant portion of our revenue. For the years ended December 31, 2010, 2009 and 2008, our top ten purchasers collectively represented approximately 80%, 72% and 71% of total revenues, respectively. Our three largest purchasers in 2010 accounted for 32%, 15% and 10% of total revenues, respectively. This concentration of purchasers may increase our overall exposure to credit risk, and our purchasers will likely be similarly affected by changes in economic and industry conditions. Our financial condition and results of operations could be materially adversely affected if one or more of our significant purchasers fails to pay us or ceases to acquire our production on terms that are favorable to us or at all. However, we believe our current purchasers could be replaced by other purchasers under contracts with similar terms and conditions.

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 natural gas and crude oil, 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 for the natural gas and crude oil we produce. There is also competition between producers of natural gas and crude oil 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 natural gas and crude 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 9. "Directors and Executive Officers of the Registrant," which information is incorporated herein by reference.

ITEM 1A. Risk Factors

Risks Related to Our Business

Natural gas, crude oil and natural gas liquids prices are volatile, and a decline in prices can significantly affect our financial results and impede our growth.

Our revenue, cash flow from operations and future growth depend upon the prices and demand for natural gas, crude oil and natural gas liquids. The markets for these commodities are very volatile. Even relatively modest drops in prices can significantly affect our financial results and impede our growth. Changes in natural gas, crude oil and natural gas liquids prices have a significant impact on the value of our reserves and on our cash flow. In addition, periods of sustained lower prices may compel us to reduce our capital expenditures and budget for drilling. Prices for natural gas, crude oil and natural gas liquids may fluctuate widely in response to relatively minor changes in the supply of and demand for natural gas, crude oil and natural gas liquids and a variety of additional factors that are beyond our control, such as:

- the domestic and foreign supply of natural gas, crude oil and natural gas liquids;
- the price of foreign imports;
- worldwide economic conditions;
- political and economic conditions in oil producing countries, including the Middle East and South America;
- the ability of members of the Organization of Petroleum Exporting Countries to agree to and maintain oil price and production controls;
- the level of consumer product demand;
- weather conditions;
- technological advances affecting energy consumption;
- availability of pipeline infrastructure, treating, transportation and refining capacity;
- domestic and foreign governmental regulations and taxes; and
- the price and availability of alternative fuels.

Lower natural gas, crude oil and natural gas liquids prices may not only decrease our revenues on a per share basis, but also may reduce the amount of natural gas, crude oil and natural gas liquids that we can produce economically. This may result in our having to make substantial downward adjustments to our estimated proved reserves.

Many of our East Texas leases are not producing and must be drilled before expiration, generally within three years, in order to hold the leases by production, or they will terminate. In the highly competitive market for Haynesville Shale acreage, failure to drill sufficient wells timely to hold this acreage will result in a substantial renewal cost, or if renewal is not feasible, loss of lease investment and prospective drilling opportunities in the Haynesville Shale, as well as in the Mid-Bossier Shale, James Lime, Pettet and Knowles Lime formations.

Our East Texas leases have three year terms which require that an initial producing well be drilled prior to expiration date or the lease will terminate. Most of our leases in this area were signed in late 2008. Generally, once an initial well is drilled and completed as a producer, the lease is extended for the duration of production subject to payment of royalties and additional wells may be drilled on that lease.

The leases in this area are extremely fragmented and much of the leased acreage is not contiguous. In many cases, contiguous leases owned by us are not large enough to accommodate horizontal drilling to the Haynesville or Mid-Bossier Shales, which usually involves a horizontal lateral of between 4,000 to 5,000 feet within lease lines. In other cases, leases may be from fractional interest land owners and may not comprise a sufficient aggregate percentage working interest to make such a well economical. As a result, in order to realize the drilling opportunities in the Haynesville Shale, Mid-Bossier Shale, James Lime, Pettet and Knowles Lime formations, we and other similarly situated major lease owners and operators in East Texas will need to cooperate and negotiate joint drilling operations to drill initial wells prior to lease expirations. These negotiations may include the right to act as operator for jointly owned wells. If we do not reach agreements with other major lease owners and operators to drill wells prior to lease expirations, or if we are unable to drill timely sufficient wells to hold our acreage, we will lose the drilling opportunities and investment in the expiring leases unless we can successfully negotiate to renew the leases. While we currently estimate that we will be able to hold, by production, up to 4,000 net acres, and may be able to re-lease, or extend least terms, on up to another 2,000 to 4,000 net acres; ,we may not be able to renew the expired leases, or if renewed, the cost of releasing could be substantial, particularly if development in this area proves successful.

Part of our strategy involves drilling in new or emerging plays; therefore, our drilling results in these areas are not certain.

The results of our drilling in new or emerging plays, such as in our East Texas resource play, are more uncertain than drilling results in areas that are more developed and have established production. Since new or emerging plays and new formations have limited or no production history, we are less able to use past drilling results in those areas to help predict our future drilling results. Accordingly, our drilling results are subject to greater risks in these areas and could be unsuccessful. We may be unable to execute our expected drilling program in these areas because of disappointing drilling results, capital constraints, lease expirations, access to adequate gathering systems or pipeline take-away capacity, availability of drilling rigs and other services or otherwise, and/or natural gas, crude oil and natural gas liquids price declines. To the extent we are unable to execute our expected drilling program in these areas, our return on investment may not be as attractive as we anticipate and our common stock price may decrease. We could incur material write-downs of unevaluated properties, and the value of our undeveloped acreage could decline in the future if our drilling results are unsuccessful.

The results of our planned drilling in our East Texas and South Texas resource plays, which are emerging plays with limited drilling and production history in certain areas, are subject to more uncertainties than our drilling program in our more established areas of operation in the onshore South Texas and U.S. Gulf Coast regions and may not meet our expectations for reserves or production.

In October 2009, we completed drilling our first well in the Haynesville Shale in East Texas, for which we are not the operator and since successfully completed three operator and one non-operator wells in the Mid-Bossier formation. We also have two operated wells awaiting completion. In late January 2011, we completed our first two horizontal wells in Bee County, Texas in the Eagle Ford Shale. The presence of the Haynesville Shale in the East Texas area where we own leases was determined after the activity in the north Louisiana portion of the Haynesville Shale play and, therefore is not yet as defined. Part of our drilling strategy to maximize recoveries from the Haynesville Shale involves the drilling of horizontal wells using completion techniques that have proven to be successful in other shale formations. Our direct experience with horizontal drilling of these shale plays is limited. Similarly, drilling activity in the Eagle Ford formation is also much less extensive and defined as more mature basins or other shale plays. The ultimate success of these drilling and completion strategies and techniques in these formations will be better evaluated over time as more wells are drilled and production profiles are better established. Accordingly, the results of our future drilling in the emerging shale plays are more uncertain than drilling results in our more established areas of operation with established reserves and production history.

Initial production rates in shale plays, and particularly in the Haynesville Shale, tend to decline steeply in the first twelve months of production and are not necessarily indicative of sustained production rates.

Initial production rates in shale plays, and particularly in the Haynesville Shale, tend to decline steeply in the first twelve months of production and are not necessarily indicative of sustained production rates.

Our development and exploration operations, including on our East Texas resource play acreage, require substantial capital, and we may be unable to obtain needed capital or financing on satisfactory terms, which could lead to a loss of properties and a decline in our natural gas, crude oil and natural gas liquids reserves.

The oil and gas industry is capital intensive. We make and expect to continue to make substantial capital expenditures in our business and operations for the exploration, development, production and acquisition of natural gas, crude oil and natural gas liquids reserves. We intend to finance our future capital expenditures primarily with cash flow from operations and borrowings under our revolving credit agreement. Our cash flow from operations and access to capital is subject to a number of variables, including:

- our proved reserves;
- the level of natural gas, crude oil and natural gas liquids we are able to produce from existing wells;
- the prices at which natural gas, crude oil and natural gas liquids are sold; and
- our ability to acquire, locate and produce new reserves.

If our revenues decrease as a result of lower natural gas, crude oil and natural gas liquids prices, operating difficulties, declines in reserves or for any other reason, we may have limited ability to obtain the capital necessary to sustain our operations at current levels, to further develop and exploit our current properties, or to conduct exploratory activity. In order to fund our capital expenditures, we may need to seek additional financing. Our credit agreements contain covenants restricting our ability to incur additional indebtedness without the consent of the lenders. Our lenders may withhold this consent in their sole discretion. In addition, if our borrowing base is redetermined resulting in a lower borrowing base under our revolving credit agreement, we may be unable to obtain financing otherwise available under our revolving credit agreement. See "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations—Liquidity and Capital Resources—Capital resources."

Furthermore, we may not be able to obtain debt or equity financing on terms favorable to us, or at all. In particular, the cost of raising money in the debt and equity capital markets has increased substantially while the availability of funds from those markets generally has diminished significantly. Also, as a result of concerns about the stability of financial markets generally and the solvency of counterparties specifically, the cost of obtaining money from the credit markets generally has increased as many lenders and institutional investors have increased interest rates, enacted tighter lending standards, refused to refinance existing debt at maturity on terms that are similar to existing debt, and reduced, or in some cases ceased, to provide funding to borrowers. The failure to obtain additional financing could result in a curtailment of our operations relating to exploration and development of our prospects, which in turn could lead to a possible loss of properties and a decline in our natural gas, crude oil and natural gas liquids reserves.

The impairment of financial institutions could adversely affect us.

We have exposure to different counterparties, and we have entered into transactions with counterparties in the financial services industry specifically, with members of our bank group. These transactions could expose us to credit risk in the event of default of our counterparty. We have exposure to these financial institutions in the form of derivative transactions in connection with our hedges. We also maintain insurance policies with insurance companies to protect us against certain risks inherent in our business. In addition, if any lender under our credit agreement is unable to fund its commitment, our liquidity could be reduced by an amount up to the aggregate amount of such lender's commitment under our credit agreement.

We have a substantial amount of indebtedness, which may adversely affect our cash flow and our ability to operate our business.

As of December 31, 2010, we had outstanding $179.0 million in principal amount of long-term debt. Our substantial level of indebtedness increases the possibility that we may be unable to pay, when due, the principal of, interest on, or other amounts due in respect of our indebtedness. Our substantial indebtedness, combined with our other financial obligations and contractual commitments, could have other important consequences, including the following:

- 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;
- we may be more highly leveraged than certain of our competitors, which may place us at a competitive disadvantage;
- certain of the borrowings under our debt agreements have floating rates of interest, which causes us to be vulnerable to increases in interest rates;
- our degree of leverage could make us more vulnerable to downturns in general economic conditions;
- our ability to plan for, or react to, changes in our business and the industry in which we operate may be limited; and
- 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 revolving credit agreement and second lien credit agreement contain a number of significant covenants that place limitations 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 agreements 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 also result in a default under our credit agreements. 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. See "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations—Liquidity and Capital Resources—Capital resources" for further information regarding future compliance with these covenants. Even if new financing were then available, it may not be on terms that are acceptable to us. See "—Recent market events and conditions, including disruptions in the U.S. and international credit markets and other financial systems and the deterioration of the U.S. and global economic conditions, could, among other things, impede access to capital or increase the cost of capital, which would have an adverse effect on our ability to fund our working capital and other capital requirements" and "—Our development and exploration operations, including on our East Texas resource play acreage, require substantial capital, and we may be unable to obtain needed capital or financing on satisfactory terms, which could lead to a loss of properties and a decline in our natural gas, crude oil and natural gas liquids reserves."

Changes to current laws may affect our ability to take certain deductions.

Substantive changes to the existing federal income tax laws have been proposed that, if adopted, would affect, among other things, our ability to take certain deductions related to our operations, including depletion deductions, deductions for intangible drilling and development costs and deductions for United States production activities. These changes, if enacted into law, could negatively affect our financial condition and results of operations.

Recent changes in the financial and credit markets may impact economic growth and natural gas, crude oil and natural gas liquids prices may continue to be adversely affected by general economic conditions.

Based on a number of economic indicators, global economic activity slowed substantially in recent years. A continued slowing of global economic growth or lack of significant improvement in the global economy (and, in particular, in the United States) will likely reduce demand for natural gas, crude oil and natural gas liquids, which in turn could likely result in lower prices for natural gas, crude oil and natural gas liquids. NYMEX settlement prices for natural gas and crude oil prices dropped dramatically in 2009 from record levels, in July 2008. While prices have improved, and we hedge prices on a meaningful portion of our forecasted production from proved developed producing reserves for up to two years forward, a reduction in demand for, and the resulting lower prices of, natural gas, crude oil and natural gas liquids could adversely affect our financial condition and results of operations.

Recent market events and conditions, including disruptions in the U.S. and international credit markets and other financial systems and the deterioration of the U.S. and global economies, could, among other things, impede our access to capital or increase our cost of capital, which would have an adverse effect on our ability to fund our working capital and other capital requirements.

Recent market events and conditions, including unprecedented disruptions in the credit and financial markets and the deterioration of economic conditions in the United States and internationally have had a significant material adverse impact on a number of financial institutions and have limited access to capital and credit for many companies. These disruptions could, among other things, make it more difficult for us to obtain, or increase our cost of obtaining, capital and financing for our operations. Access to additional capital may not be available on terms acceptable to us or at all. Difficulties in obtaining capital and financing or increased costs for obtaining capital and financing for our operations would have an adverse effect on our ability to fund our working capital and other capital requirements.

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. Our future operating results may fluctuate significantly depending upon a number of factors, including industry conditions, prices of natural gas, crude oil and natural gas liquids, rates of production, timing of capital expenditures and drilling success. Negative changes in these variables could have a material adverse effect on our business, financial condition, results of operations and the market value of our common stock.

We may not be able to fully realize the value of our net operating loss carryforwards for Federal income tax purposes.

As of December 31, 2010, we had net operating loss carryforwards (NOLs) of approximately $98.6 million, which are available to reduce our future federal taxable income and related income tax liability. Based upon the level of historical taxable income and our projections for future taxable income over the periods in which the deferred tax assets are deductible, we believe it is more likely than not that we will realize the benefits of these NOLs to reduce future Federal net income tax obligations. Future net losses could affect our ability to realize during the appropriate carryforward periods our available net operating loss carryforwards for Federal income tax purposes and the value of the related deferred tax asset. Our ability to use our available net operating loss carryforwards and the amount of the related deferred tax asset ultimately realizable could be reduced in the future if our estimates of future taxable income during the carryforward periods are reduced.

We currently expect we will not be able to utilize NOLs of approximately $9.1 million of due to prior occurrences of an “ownership change”, as determined under Section 382 of the Internal Revenue Code, as amended. If we were to experience a further “ownership change,” as determined under Section 382, our ability to offset taxable income arising after the ownership change with NOLs arising prior to the ownership change would be limited, possibly substantially. An ownership change would establish an annual limitation on the amount of our pre-change NOLs we could utilize to offset our taxable income in any future taxable year to an amount generally equal to the value of our stock immediately prior to the ownership change multiplied by the highest long-term tax-exempt rate during the three months prior to the date of the ownership change. The long-term tax-exempt rate is a rate published each month by the Internal Revenue Service. The application of this limitation could prevent full utilization of our pre-change NOLs arising prior to their expiration. It is possible that additional issuances of our common stock within the next few years, or the sale of our common stock by our larger shareholders, could cause us to experience another ownership change, in which case any NOLs existing at the time of the change would be limited in the manner described above.

Reserve estimates depend on many assumptions that may turn out to be inaccurate. Any material inaccuracies in these reserve estimates or underlying assumptions could materially reduce the estimated quantities and present value of our reserves.

The process of estimating natural gas, crude oil and natural gas liquids reserves is complex. It requires interpretations of available technical data and many estimates, including estimates based upon assumptions relating to economic factors. Any significant inaccuracies in these interpretations or estimates could materially reduce the estimated quantities and present value of reserves shown in this Annual Report. See “Item 1. Business” for information about our natural gas, crude oil and natural gas liquids reserves.

In order to prepare our estimates, we must project production rates and timing of development expenditures. We must also analyze available geological, geophysical, production and engineering data. The extent, quality and reliability of this data can vary. The process also requires economic assumptions about matters such as natural gas, crude oil and natural gas liquids prices, drilling and operating expenses, the amount and timing of capital expenditures, taxes and the availability of funds.

Actual future production, natural gas, crude oil and natural gas liquids prices, revenues, taxes, development expenditures, operating expenses and quantities of recoverable natural gas, crude oil and natural gas liquids reserves most likely will vary from our estimates. Any significant variance could materially affect the estimated quantities and present value of reserves shown in this Annual Report. In addition, we may adjust estimates of proved reserves to reflect production history, results of exploration and development, prevailing natural gas, crude oil and natural gas liquids prices and other factors, many of which are beyond our control.

Approximately 51.9% of our total estimated proved reserves at December 31, 2010 were proved undeveloped reserves.

Recovery of proved undeveloped reserves requires significant capital expenditures and successful drilling operations. The reserve data included in the reserve engineer reports assumes that substantial capital expenditures are required to develop such reserves. Although cost and reserve estimates attributable to our natural gas, crude oil and natural gas liquids 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.

The present value of future net cash flows from our proved reserves will not necessarily be the same as the current market value of our estimated natural gas, crude oil and natural gas liquids reserves.

You should not assume that the present value of future net revenues from our proved reserves referred to in this Annual Report is the current market value of our estimated natural gas, crude oil and natural gas liquids reserves. In accordance with the requirements of the SEC, the estimated discounted future net cash flows from our proved reserves are based on prices and costs on the date of the estimate, held flat for the life of the properties. Actual future prices and costs may differ materially from those used in the present value estimate. The present value of future net revenues from our proved reserves as of December 31, 2010 was based on the 12-month unweighted arithmetic average of the first-day-of-the-month price for the period January through December 2010. For crude oil and natural gas liquids volumes, the average West Texas Intermediate posted price was $75.96 per barrel. For natural gas volumes, the average Henry Hub spot price was $4.376 per MMBtu. If crude oil prices were $1.00 per Bbl lower than the price used, our PV-10 as of December 31, 2010 would have decreased from $239.7 million to $237.5 million. If natural gas prices were $0.10 per Mcf lower than the price used, our PV-10 as of

December31, 2010, would have decreased from $239.7 million to $232.4 million. Any adjustments to the estimates of proved reserves or decreases in the price of crude oil or natural gas may decrease the value of our common stock. PV-10 is a non-GAAP financial measure. A reconciliation of our Standardized Measure of Discounted Future Net Cash Flows to PV-10 is provided under "Item 2. Properties — Proved Reserves".

Actual future net cash flows will also be affected by increases or decreases in consumption by oil and gas purchasers and changes in governmental regulations or taxation. The timing of both the production and the incurrence of expenses in connection with the development and production of oil and gas properties affects the timing of actual future net cash flows from proved reserves. In addition, the 10% discount factor, which is required by the SEC 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.

Our use of 2D and 3D seismic data is subject to interpretation and may not accurately identify the presence of natural gas, crude oil and natural gas liquids. In addition, the use of such technology requires greater predrilling expenditures, which could adversely affect the results of our drilling operations.

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. For example, we have over 4,200 square miles of 3D data in the South Texas and Gulf Coast regions. However, even when used and properly interpreted, 3D 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. Other geologists and petroleum professionals, when studying the same seismic data, may have significantly different interpretations than our professionals.

In addition, the use of 3D seismic and other advanced technologies requires greater predrilling expenditures than traditional drilling strategies, and we could incur losses due to such expenditures. As a result, our drilling activities may not be geologically successful or economical, and our overall drilling success rate or our drilling success rate for activities in a particular area may not improve.

Drilling for and producing natural gas, crude oil and natural gas liquids are high risk activities with many uncertainties that could adversely affect our business, financial condition or results of operations.

Our drilling and operating activities are subject to many risks, including the risk that we will not discover commercially productive reservoirs. Drilling for natural gas, crude oil and natural gas liquids can be unprofitable, not only from dry holes, but from productive wells that do not produce sufficient revenues to return a profit. In addition, our drilling and producing operations may be curtailed, delayed or canceled as a result of other factors, including:

- unusual or unexpected geological formations and miscalculations;
- pressures;
- fires;
- explosions and blowouts;
- pipe or cement failures;
- environmental hazards, such as natural gas leaks, pipeline ruptures and discharges of toxic gases;
- loss of drilling fluid circulation;
- title problems;
- facility or equipment malfunctions;

- unexpected operational events;
- shortages of skilled personnel;
- shortages or delivery delays of equipment and services;
- compliance with environmental and other regulatory requirements;
- natural disasters; and
- adverse weather conditions.

Any of these risks can cause substantial losses, including personal injury or loss of life; severe damage to or destruction of property, natural resources and equipment; pollution; environmental contamination; clean-up responsibilities; loss of wells; repairs to resume operations; and regulatory fines or penalties.

Insurance against all operational risks is not available to us. Additionally, we may elect not to obtain insurance if we believe that the cost of available insurance is excessive relative to the perceived risks presented. We carry limited environmental insurance, thus, losses could occur for uninsurable or uninsured risks or in amounts in excess of existing insurance coverage. The occurrence of an event that is not covered in full or in part by insurance could have a material adverse impact on our business activities, financial condition and results of operations.

Our acquisition strategy may subject us to greater risks.

The successful acquisition of properties requires an assessment of recoverable reserves, future natural gas, crude oil and natural gas liquids 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, costs and liabilities, nor will it permit us, as the buyer, to become sufficiently familiar with the properties to assess their capabilities or deficiencies fully. We may not inspect every well and, even when an inspection is undertaken, structural and environmental problems may not necessarily be observable.

We may be unable 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:

- acquisitions may prove unprofitable and fail to generate anticipated cash flows;
- we may need to (i) recruit additional personnel and 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.

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 natural gas, crude oil and natural gas liquids 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 natural gas, crude oil and natural gas liquids properties that have economically recoverable reserves for acceptable prices.

We cannot control activities on properties that we do not operate and are unable to control their proper operation and profitability.

We do not operate a significant portion of the properties in which we own an interest. As a result, we have limited ability to exercise influence over, and control the risks associated with, the operations of these properties. The failure of an operator of our wells to adequately perform operations, an operator's breach of the applicable agreements or an operator's failure to act in ways that are in our best interests could reduce our production and revenues. The success and timing of our drilling and development activities on properties operated by others therefore depend upon a number of factors outside of our control, including:

- the nature and timing of drilling and operational activities;
- the timing and amount of capital expenditures;
- the operator's expertise and financial resources;
- the operator's ability to procure drilling and completion services;
- the approval of other participants in drilling wells; and
- the operator's selection of suitable technology.

If our access to markets is restricted, it could negatively impact our production, our income and ultimately our ability to retain our leases.

Market conditions or the unavailability of satisfactory natural gas, crude oil and natural gas liquids transportation arrangements may hinder our access to natural gas, crude oil and natural gas liquids markets or delay our production. The availability of a ready market for our natural gas, crude oil and natural gas liquids production depends on a number of factors, including the demand for and supply of natural gas, crude oil and natural gas liquids and the proximity of reserves to pipelines and terminal facilities. Our ability to market our production depends in substantial part on the availability and capacity of gathering systems, pipelines and processing facilities owned and operated by third parties. Our failure to obtain such services on acceptable terms could materially harm our business. Our productive properties may be located in areas with limited or no access to pipelines, thereby necessitating delivery by other means, such as trucking, or requiring compression facilities. Such restrictions on our ability to sell our natural gas, crude oil and natural gas liquids may have several adverse effects, including higher transportation costs, fewer potential purchasers (thereby potentially resulting in a lower selling price) or, in the event we were unable to market and sustain production from a particular lease for an extended time, possible loss of a lease due to lack of production.

Unless we replace our natural gas, crude oil and natural gas liquids reserves, our reserves and production will decline, which would adversely affect our cash flows, our ability to raise capital and the value of our common stock.

Unless we conduct successful development, exploitation and exploration activities or acquire properties containing proved reserves, our proved reserves will decline as those reserves are produced. Producing natural gas, crude oil and natural gas liquids reservoirs generally are characterized by declining production rates that vary depending upon reservoir characteristics and other factors. Our future natural gas, crude oil and natural gas liquids reserves and production, and therefore our cash flow and results of operations, are highly dependent on our success in efficiently developing and exploiting our current reserves and economically finding or acquiring additional recoverable reserves. The value of our common stock and our ability to raise capital will be adversely impacted if we are not able to replace our reserves that are depleted by production. We may not be able to develop, exploit, find or acquire sufficient additional reserves to replace our current and future production.

The potential lack of availability or high cost of drilling rigs, equipment, supplies, personnel and crude oil field services could adversely affect our ability to execute on a timely basis our exploration and development plans within our budget.

When the prices of natural gas, crude oil and natural gas liquids increase, we typically encounter an increase in the cost of securing drilling rigs, equipment and supplies. In addition, larger producers may be more likely to secure access to such equipment by offering more lucrative terms. If we are unable to acquire access to such resources, or can obtain access only at higher prices, our ability to convert our reserves into cash flow could be delayed and the cost of producing those reserves could increase significantly, which would adversely affect our results of operations and financial condition.

Our hedging activities could result in financial losses or reduce our income.

To achieve a more predictable cash flow and to reduce our exposure to adverse fluctuations in the prices of natural gas, crude oil and natural gas liquids, as well as interest rates, we currently, and may in the future, enter into derivative arrangements for a significant portion of our natural gas, crude oil and/or natural gas liquids production and our debt that could result in both realized and unrealized hedging losses. We utilize financial commodity price hedge instruments to minimize exposure to declining prices on our crude oil, natural gas and natural gas liquids production. We typically use a combination of swaps and costless collars. We use interest rate swaps to minimize exposure to rising interest rates.

Our actual future production may be significantly higher or lower than we estimate at the time we enter into hedging transactions for such period. If the actual amount is higher than we estimate, we will have greater commodity price exposure than we intended. If the actual amount is lower than the nominal amount that is subject to our derivative financial instruments, we might be forced to satisfy all or a portion of our derivative transactions without the benefit of the cash flow from our sale or purchase of the underlying physical commodity, resulting in a substantial diminution of our liquidity. As a result of our interest rate swap agreements, we may fail to benefit when rates fall, to the extent we have agreed to pay interest at a fixed rate, or face a greater degree of exposure when rates increase, to the extent we have agreed to pay interest at a floating rate. As a result of these factors, our hedging activities may not be as effective as we intend in reducing the volatility of our cash flows, and in certain circumstances may actually increase the volatility of our cash flows.

Competition in the oil and gas industry is intense, and many of our competitors have resources that are greater than ours.

We operate in a highly competitive environment for acquiring prospects and productive properties, marketing natural gas, crude oil and natural gas liquids, and securing equipment and trained personnel. Many of our competitors possess and employ financial, technical and personnel resources substantially greater than ours. Those companies may be able to develop and acquire more prospects and productive properties than our financial or personnel resources permit. Our ability to acquire additional prospects and discover reserves in the future will depend on our ability to evaluate and select suitable properties and consummate transactions in a highly competitive environment. Also, there is substantial competition for capital available for investment in the oil and gas industry. Our larger competitors may be better able to withstand sustained periods of unsuccessful drilling and absorb the burden of changes in laws and regulations more easily than we can, which would adversely affect our competitive position. We may not be able to compete successfully in the future in acquiring prospective reserves, developing reserves, marketing hydrocarbons, attracting and retaining quality personnel and raising additional capital.

We depend on our senior management team and other key personnel. Accordingly, the loss of any of these individuals could adversely affect our business, financial condition and the results of operations and future growth.

Our success is largely dependent on the skills, experience and efforts of our management team and employees. The loss of the services of one or more members of our senior management team or of our other employees with critical skills needed to operate our business could have a negative effect on our business, financial conditions and results of operations and future growth. Our ability to manage our growth, if any, will require us to continue to train, motivate and manage our employees and to attract, motivate and retain additional qualified personnel.

Competition for these types of personnel is intense and we may not be successful in attracting, assimilating and retaining the personnel required to grow and operate our business profitably.

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

Our operations are subject to complex and stringent laws and regulations. In order to conduct our operations in compliance with these laws and regulations, we must obtain and maintain numerous permits, approvals and certificates from various federal, state and local governmental authorities. We may incur substantial costs in order to maintain compliance with these existing laws and regulations. In addition, our costs of compliance may increase if existing laws and regulations are revised or reinterpreted, or if new laws and regulations become applicable to our operations. For instance, we may be unable to obtain all necessary permits, approvals and certificates for proposed projects. Alternatively, we may have to incur substantial expenditures to obtain, maintain or renew authorizations to conduct existing projects. If a project is unable to function as planned due to changing requirements or public opposition, we may suffer expensive delays, extended periods of non-operation or significant loss of value in a project. All such costs may have a negative effect on our business and results of operations.

Our business is subject to federal, state and local regulations as interpreted and enforced by governmental agencies and other bodies vested with much authority relating to the exploration for, and the development, production, transportation and marketing of, natural gas, crude oil and natural gas liquids. Failure to comply with such laws and regulations, as interpreted and enforced, could have a material adverse effect on us.

Climate change legislation or regulations restricting emissions of greenhouse gases could result in increased operating costs and reduced demand for the oil and natural gas we produce.

In December 2009, the U.S. Environmental Protection Agency, or "EPA," determined that emissions of carbon dioxide, methane, and other greenhouse gases, or "GHGs," present an endangerment to public health and the environment because emissions of such gasses are contributing to the warming of the earth's atmosphere and other climatic changes. Based on these findings, the EPA recently adopted regulations under existing provisions of the CAA that require a reduction in emissions of GHGs from motor vehicles and the other of which regulates emissions of GHGs from certain large stationary sources, effective January 2, 2011. The EPA has published its final rule to address the permitting of GHG emissions from stationary sources under the Prevention of Significant Deterioration, or "PSD," and Title V permitting programs, pursuant to which these permitting programs have been "tailored" to apply to certain stationary sources of GHG emissions in a multi-step process, with the largest sources first subject to permitting. Facilities required to obtain PSD permits for their GHG emissions also will be required to meet "best available control technology" standards, which will be established by the states or, in some instances, by the EPA on a case-by-case basis. The EPA's rules relating to emissions of GHGs from large stationary sources of emissions are currently subject to a number of legal challenges but the federal courts have thus far declined to issue any injunctions to prevent EPA from implementing or requiring state environmental agencies to implement the rules. These EPA rulemakings could adversely affect our operations and restrict or delay our ability to obtain air permits for new or modified facilities. The EPA has also adopted regulations requiring the reporting of GHG emissions from specified large GHG emission sources in the United States including certain onshore and offshore oil and natural gas production facilities, which may include certain of our operations, beginning in 2012 for emissions occurring in 2011.

In addition, Congress has from time to time considered adopting legislation to reduce emissions of GHGs and almost one-half of the states have already taken legal measures to reduce emissions of GHGs primarily through the planned development of GHG emission inventories and/or regional GHG cap and trade programs. Most of these cap and trade programs work by requiring either major sources of emissions or major producers of fuels to acquire and surrender emission allowances, with the number of allowances available for purchase reduced each year until the overall GHG emission reduction goal is achieved. These allowances would be expected to escalate significantly in cost over time. The adoption of legislation or regulatory programs to reduce emissions of GHGs could require us to incur increased operating costs, such as costs to purchase and operate emissions control systems, to acquire emissions allowances or comply with new regulatory or reporting requirements. Any such legislation or regulatory programs could also increase the cost of consuming, and thereby reduce demand for, the oil and natural gas we produce. Consequently, legislation and regulatory programs to reduce emissions of GHGs could have an adverse effect on our business, financial condition and results of operations. Finally, it should be noted that some scientists have concluded that increasing concentrations of GHGs in the Earth's atmosphere may produce climate changes that have significant physical effects, such as increased frequency and severity of storms, floods and other climatic events. If any such effects were to occur, they could have an adverse effect on our financial condition and results of operations.

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

Hydraulic fracturing is an important and commonly used process for the completion of natural gas, and to a lesser extent, oil wells in shale formations, and involves the pressurized injection of water, sand and chemicals into rock formations to stimulate natural gas production. The process is typically regulated by state oil and gas commissions. However, the EPA recently asserted federal regulatory authority over hydraulic fracturing involving diesel additives under the federal Safe Drinking Water Act's Underground Injection Program. While the EPA has yet to take any action enforce or implement this newly asserted regulatory authority, industry groups have filed suit challenging the EPA's recent decision. At the same time, the EPA has commenced a study of the potential environmental impacts of hydraulic fracturing activities, with results of the study anticipated to be available by late 2012, and a committee of the U.S. House of Representatives is conducting an investigation of hydraulic fracturing practices. In addition, legislation was proposed in the recently completed session of Congress to provide for federal regulation of hydraulic fracturing and to require disclosure of the chemicals used in the fracturing process, and such legislation could be introduced in the current session of Congress. Also, various state and local governments are considering increased regulatory oversight of hydraulic fracturing through additional permit requirements, operational restrictions, and temporary or permanent bans on hydraulic fracturing in certain environmentally sensitive areas such as watersheds. The adoption of any federal or state legislation or implementing regulations imposing reporting obligations on, or otherwise limiting, the hydraulic fracturing process could lead to operational delays or increased operating costs and could result in additional regulatory burdens that could make it more difficult to perform hydraulic fracturing and increase our costs of compliance and doing business.

Our operations are subject to environmental, health and safety matters.

Our oil and natural gas exploration and production operations are subject to stringent and complex federal, state and local laws and regulations governing health and safety aspects of our operations, the discharge of materials into the environment or otherwise relating to environmental protection. These laws and regulations may impose numerous obligations that are applicable to our operations including the acquisition of a permit before conducting drilling or underground injection activities; the restriction of types, quantities and concentration of materials that can be released into the environment; the limitation or prohibition of drilling activities on certain lands lying within wilderness, wetlands and other protected areas; the application of specific health and safety criteria addressing worker protection; and the imposition of substantial liabilities for pollution resulting from operations. Numerous governmental authorities, such as the U.S. Environmental Protection Agency, or the "EPA," and analogous state agencies have the power to enforce compliance with these laws and regulations and the permits issued under them, oftentimes requiring difficult and costly actions. Failure to comply with these laws and regulations may result in the assessment of sanctions, including administrative, civil or criminal penalties, the imposition of investigatory or remedial obligations, and the issuance of orders limiting or prohibiting some or all of our operations.

There is inherent risk of incurring significant environmental costs and liabilities in the performance of our operations due to our handling of petroleum hydrocarbons and wastes, because of air emissions and wastewater discharges related to our operations, and as a result of historical industry operations and waste disposal practices. Under certain environmental laws and regulations, we could be subject to joint and several, strict liability for the removal or remediation of previously released materials or property contamination regardless of whether we were responsible for the release or contamination or whether the operations were in compliance with all applicable laws at the time those actions were taken. Private parties, including the owners of properties upon which our wells are drilled and facilities where our petroleum hydrocarbons or wastes are taken for reclamation or disposal, also may have the right to pursue legal actions to enforce compliance as well as to seek damages for non-compliance with environmental laws and regulations or for personal injury or property or natural resource damages. In addition, the risk of accidental spills or releases could expose us to significant liabilities that could have a material adverse effect on our business, financial condition or results of operations. Changes in environmental laws and regulations occur frequently, and any changes that result in more stringent or costly waste control, handling, storage, transport, disposal or cleanup requirements could require us to make significant expenditures to attain and maintain compliance and may otherwise have a material adverse effect on our own results of operations, competitive position or financial condition. We may not be able to recover some or any of these costs from insurance. See "Item 1. Business—Environmental Regulations."

If we are unable to successfully prevent or address material weaknesses in our internal control over financial reporting, or any other control deficiencies, our ability to report our financial results on a timely and accurate basis and to comply with disclosure and other reporting requirements may be adversely affected.

While we have taken actions designed to address compliance with the internal control, disclosure control and other requirements of the Sarbanes-Oxley Act of 2002 and the rules and regulations promulgated by the SEC implementing these requirements, there are inherent limitations in our ability to control all circumstances. Our management, including our Chief Executive Officer and Chief Financial Officer, does not expect that our internal controls and disclosure controls will prevent all errors and all fraud. A control system, no matter how well conceived and operated, can provide only reasonable, not absolute, assurance that the objectives of the control system are met. For example, for the quarter ended March 31, 2007, our management concluded that our historical documentation of related tax positions could have resulted in a material misstatement to our annual or interim financial statements and, accordingly, concluded that this deficiency was a material weakness. Although this material weakness was subsequently remedied, if we are unable to successfully prevent or address these and other material weaknesses in our internal control systems, our ability to report our financial results on a timely and accurate basis and to comply with disclosure and other reporting requirements may be adversely affected.

The recent adoption of derivatives legislation by the U.S. Congress could have an adverse effect on our ability to use derivative instruments to reduce the effect of commodity price, interest rate and other risks associated with our business.

The U.S. Congress recently adopted comprehensive financial reform legislation that establishes federal oversight and regulation of the over-the-counter derivatives market and entities, such as the Company, that participate in that market. The new legislation was signed into law by President Obama on July 21, 2010 and requires the Commodities Futures Trading Commission (the "CFTC") and the SEC to promulgate rules and regulations implementing the new legislation within 360 days from the date of enactment. The CFTC has also proposed regulations to set position limits for certain futures and option contracts in the major energy markets, although it is not possible at this time to predict whether or when the CFTC will adopt those rules or include comparable provisions in its rulemaking under the new legislation. The financial reform legislation may also require us to comply with margin requirements and with certain clearing and trade-execution requirements in connection with our derivative activities, although the application of those provisions to us is uncertain at this time. The financial reform legislation may also require the counterparties to our derivative instruments to spin off some of their derivatives activities to a separate entity, which may not be as creditworthy as the current counterparty. The new legislation and any new regulations could significantly increase the cost of derivative contracts (including through requirements to post collateral which could adversely affect our available liquidity), materially alter the terms of derivative contracts, reduce the availability of derivatives to protect against risks we encounter, reduce our ability to monetize or restructure our existing derivative contracts, and increase our exposure to less creditworthy counterparties. If we reduce our use of derivatives as a result of the legislation and regulations, our results of operations may become more volatile and our cash flows may be less predictable, which could adversely affect our ability to plan for and fund capital expenditures. Finally, the legislation was intended, in part, to reduce the volatility of oil and natural gas prices, which some legislators attributed to speculative trading in derivatives and commodity instruments related to oil and natural gas. Our revenues could therefore be adversely affected if a consequence of the legislation and regulations is to lower commodity prices. Any of these consequences could have a material, adverse effect on us, our financial condition, and our results of operations.

Risks Related to an Investment in Our Common Stock

Two stockholders hold a significant number of our shares, which will limit your ability to influence corporate activities and may adversely affect the market price of our common stock, and those stockholders' interests may conflict with the interests of our other stockholders.

Of the approximately 44.9 million shares of our common stock outstanding at December 31, 2010, approximately 15.5 million shares are beneficially held by OCM GW Holdings, LLC ("*Oaktree Holdings*") and 6.0 million shares are beneficially held by America Capital Energy Corporation ("*ACEC*"). As a result, Oaktree Holdings owns or controls outstanding common stock representing, in the aggregate, an approximate 34.6% voting interest in us and ACEC owns or controls outstanding common stock representing, in the aggregate, an approximate 13.4% voting interest in us. As a result of this stock ownership, Oaktree Holdings and ACEC will possess significant influence over matters requiring approval by our stockholders, including the adoption of amendments to our certificate of incorporation and bylaws and significant corporate transactions. Such ownership and control may also have the effect of delaying or preventing a future change of control, impeding a merger, consolidation, takeover or other business combination or discouraging a potential acquirer from making a tender offer or otherwise attempting to obtain control of our company.

Oaktree Holdings, ACEC and their respective affiliates engage, from time to time in the ordinary course of their respective businesses, in trading securities of, and investing in, energy companies. As a result, conflicts may arise between the interests of Oaktree Holdings or ACEC, on the one hand, and the interests of our other stockholders, on the other hand. Either Oaktree Holdings or ACEC may, from time to time, compete directly or indirectly with us or prevent us from taking advantage of corporate opportunities. Either Oaktree Holdings or ACEC may also pursue acquisition opportunities that may be complementary to our business, and as a result, those acquisition opportunities may not be available to us.

The price of our common stock may fluctuate significantly, and you could lose all or part of your investment.

Volatility in the market price of our common stock may prevent you from being able to sell your common stock at or above the price you paid for your common stock. The market price for our common stock could fluctuate significantly for various reasons, including:

- our operating and financial performance and prospects;
- our quarterly or annual earnings or those of other companies in our industry;
- conditions that impact demand for natural gas, crude oil and natural gas liquids;
- future announcements concerning our business;
- changes in financial estimates and recommendations by securities analysts;
- actions of competitors;
- market and industry perception of our success, or lack thereof, in pursuing our growth strategy;
- strategic actions by us or our competitors, such as acquisitions or restructurings;
- changes in government and environmental regulation;
- general market, economic and political conditions;
- changes in accounting standards, policies, guidance, interpretations or principles;
- sales of common stock by us or members of our management team; and
- natural disasters, terrorist attacks and acts of war.

In addition, in recent years, the stock market has experienced significant price and volume fluctuations. This volatility has had a significant impact on the market price of securities issued by many companies, including companies in our industry. The changes frequently appear to occur without regard to the operating performance of the affected companies. Hence, the price of our common stock could fluctuate based upon factors that have little or nothing to do with our company, and these fluctuations could materially reduce our share price.

We have no plans to pay regular dividends on our common stock, so you may not receive funds without selling your common stock.

Our board of directors presently intends to retain all of our earnings for the expansion of our business; therefore, we have no plans to pay regular dividends on our common stock. Any payment of future dividends will be at the discretion of our board of directors and will depend on, among other things, our earnings, financial condition, capital requirements, level of indebtedness, statutory and contractual restrictions applying to the payment of dividends, and other considerations that our board of directors deems relevant. Also, the provisions of our revolving credit agreement and second lien credit agreement restrict the payment of dividends. Accordingly, you may have to sell some or all of your common stock in order to generate cash flow from your investment.

Future sales or the possibility of future sales of a substantial amount of our common stock may depress the price of shares of our common stock.

Future sales or the availability for sale of substantial amounts of our common stock in the public market could adversely affect the prevailing market price of our common stock and could impair our ability to raise capital through future sales of equity securities.

We may issue shares of our common stock or other securities from time to time as consideration for future acquisitions and investments. If any such acquisition or investment is significant, the number of shares of our common stock, or the number or aggregate principal amount, as the case may be, of other securities that we may issue may in turn be substantial. We may also grant registration rights covering those shares of our common stock or other securities in connection with any such acquisitions and investments.

As of December 31, 2010, we had approximately 1.7 million options to purchase shares of our common stock outstanding, of which 1.3 million were vested.

We cannot predict the size of future issuances of our common stock or the effect, if any, that future issuances and sales of our common stock will have on the market price of our common stock. Sales of substantial amounts of our common stock (including shares of our common stock issued in connection with an acquisition), or the perception that such sales could occur, may adversely affect prevailing market prices for our common stock.

Our organizational documents may impede or discourage a takeover, which could deprive our investors of the opportunity to receive a premium for their shares.

Provisions of our certificate of incorporation and bylaws may make it more difficult for, or prevent a third party from, acquiring control of us without the approval of our board of directors. These provisions:

- permit us to issue, without any further vote or action by the stockholders, additional shares of preferred stock in one or more series and, with respect to each such series, to fix the number of shares constituting the series and the designation of the series, the voting powers (if any) of the shares of the series, and the preferences and relative, participating, optional, and other special rights, if any, and any qualification, limitations or restrictions of the shares of such series;

- require special meetings of the stockholders to be called by the Chairman of the Board, the Chief Executive Officer, the President, or by resolution of a majority of the board of directors;

- require business at special meetings to be limited to the stated purpose or purposes of that meeting;

- require that stockholder action be taken at a meeting rather than by written consent, unless approved by our board of directors;

- require that stockholders follow certain procedures, including advance notice procedures, to bring certain matters before an annual meeting or to nominate a director for election; and

- permit directors to fill vacancies in our board of directors.

The foregoing factors, as well as the significant common stock ownership by Oaktree Holdings and ACEC, could discourage potential acquisition proposals and could delay or prevent a change of control.

We are subject to the Delaware business combination law.

We are subject to the provisions of Section 203 of the Delaware General Corporation Law. In general, Section 203 prohibits a publicly held Delaware corporation from engaging in a "business combination" with an "interested stockholder" for a period of three years after the date of the transaction in which the person became an interested stockholder, unless the business combination is approved in a prescribed manner.

Section 203 defines a "business combination" as a merger, asset sale or other transaction resulting in a financial benefit to the interested stockholders. Section 203 defines an "interested stockholder" as a person who, together with affiliates and associates, owns, or, in some cases, within three years prior, did own, 15% or more of the corporation's voting stock. Under Section 203, a business combination between us and an interested stockholder is prohibited unless:

- our board of directors approved either the business combination or the transaction that resulted in the stockholders becoming an interested stockholder prior to the date the person attained the status;

- upon consummation of the transaction that resulted in the stockholder becoming an interested stockholder, the interested stockholder owned at least 85% of our voting stock outstanding at the time the transaction commenced, excluding, for purposes of determining the number of shares outstanding, shares owned by persons who are directors and also officers and issued employee stock plans, under which employee participants do not have the right to determine confidentially whether shares held under the plan will be tendered in a tender or exchange offer; or

- the business combination is approved by our board of directors on or subsequent to the date the person became an interested stockholder and authorized at an annual or special meeting of the stockholders by the affirmative vote of the holders of at least 66 2/3% of the outstanding voting stock that is not owned by the interested stockholder.

This provision has an anti-takeover effect with respect to transactions not approved in advance by our board of directors, including discouraging takeover attempts that might result in a premium over the market price for the shares of our common stock. With approval of our stockholders, we could amend our certificate of incorporation in the future to elect not to be governed by the anti-takeover law.

We have "blank check" preferred stock.

Our certificate of incorporation authorizes the board of directors to issue preferred stock without further stockholder 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 our company.

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 December 31, 2010, there were approximately 44.9 million shares of common stock issued and outstanding. Since the holders of our common stock do not have cumulative voting rights, the holders of a majority of the shares of common stock present, in person or by proxy, will be able to elect all of the members of our board of directors. The holders of shares of our common stock do not have preemptive rights or rights to convert their common stock into other securities.

ITEM 2. Properties

As of December 31, 2010, we operated a majority of our producing wells and held an average 51% working interest. 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. Substantially all of our properties are located onshore in Texas. As of December 31, 2010, our properties were located in the following regions: East Texas, Southeast Texas, South Texas and Colorado and Other. We intend to allocate a substantial portion of our drilling capital budget in the next several years to the development of the significant potential that we believe exists in our resource plays depending on commodity price environment, drilling and service costs, success rates and capital availability.

Proved Reserves

Estimates of proved reserves at December 31, 2010, 2009, and 2008 were prepared by Netherland, Sewell & Associates, Inc. (*"Netherland, Sewell"*), our independent consulting petroleum engineers in accordance with the definitions and guidelines of the SEC. The scope and results of their procedures are summarized in a letter which is included as an exhibit to this Annual Report on Form 10-K. The technical persons responsible for preparing the reserve estimates are independent petroleum engineers and geoscientists that meet the requirements regarding qualifications, independence, objectivity, and confidentiality set forth in the Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information promulgated by the Society of Petroleum Engineers.

The estimated proved reserves were reviewed by our corporate reservoir engineering group and by certain members of our senior management team. We maintain an internal staff of reservoir engineers and geoscience professionals who work closely with our independent petroleum consultant to ensure the integrity, accuracy and timeliness of the data, methods and assumptions used in the preparation of the reserves estimates.

The following tables reflect our estimated proved reserves at December 31 for each of the preceding three years. The 2009 information reflects the disposition of substantially all of our Southwest Louisiana properties, resulting in the disposition of 7,631 MMcfe in 2009. See "Management's Discussion and Analysis of Financial Condition and Results of Operations—Recent Developments—Southwest Louisiana Disposition."

	2010	2009	2008
Natural Gas (MMcf)			
Developed	60,325	49,075	66,712
Undeveloped	75,350	20,785	29,457
Total	135,675	69,860	96,169
Crude Oil (MBbl)			
Developed	1,403	1,274	1,616
Undeveloped	761	690	948
Total	2,164	1,964	2,564
Natural Gas Liquids (MBbl)			
Developed	1,898	1,977	2,423
Undeveloped	1,075	664	976
Total	2,973	2,641	3,399
Total MMcfe			
Developed	80,130	68,581	90,946
Undeveloped	86,368	28,908	41,001
Total	166,498	97,489	131,947
Proved developed reserves percentage	48%	70%	69%
PV-10 (in millions)	$ 239.7	$ 176.4	$ 291.0
Estimated reserve life (in years)	12.9	7.1	6.9
Prices utilized in estimates:			
Natural gas ($/MMBtu)	$ 4.38	$ 3.87	$ 5.71
Crude oil ($/Bbl)	$ 75.96	$ 57.65	$ 41.00
Natural gas liquids ($/Bbl)	$ 40.38	$ 30.77	$ 26.71

Under SEC rules, prices used in determining our proved reserves as of December 31, 2010 are based upon an unweighted 12-month first day of the month average price per MMBtu (Henry Hub spot) of natural gas and per barrel of oil (West Texas Intermediate posted). Prior to 2009, natural gas prices were based on the Henry Hub spot price at year end and crude oil prices were based upon the West Texas Intermediate posted price at year end. All prices, under both sets of rules, are adjusted for quality, energy content, transportation fees and regional price differentials in determining proved reserves. Prices for natural gas liquids in the table represent average prices for natural gas liquids used in the proved reserve estimates, calculated in accordance with applicable SEC rules.

PV-10

PV-10 at year-end is a non-GAAP financial measure and represents the present value of estimated future cash inflows from proved natural gas and crude oil reserves, less future development and productions costs, discounted at 10% per annum to reflect timing of future cash flows and using pricing assumptions in effect at the end of the period. PV-10 differs from Standardized Measure of Discounted Future Net Cash Flows because it does not include the effects of income taxes or non-property related expenses such as general and administrative expenses and debt service or depreciation, depletion and amortization on future net revenues. Neither PV-10 nor Standardized Measure represents an estimate of fair market value of our natural gas and crude oil properties. PV-10 is used by the industry and by our management as an arbitrary reserve asset value measure to compare against past reserve bases and the reserve bases of other business entities that are not dependent on the taxpaying status of the entity.

The following table provides a reconciliation of our Standardized Measure of Discounted Future Net Cash Flows to PV-10:

	December 31, 2010	December 31, 2009	December 31, 2008
	(in millions)		
Standardized measure of discounted future net cash flows	$ 226.5	$ 176.4	$ 260.9
Present value of future income taxes discounted at 10%	13.2	—	30.1
PV-10	$ 239.7	$ 176.4	$ 291.0

The following table reflects our estimated proved reserves by category as of December 31, 2010.

	Natural Gas (MMcf)	Crude Oil (MBbl)	Natural Gas Liquids (MBbl)	Total (MMcfe)	% of Total Proved	PV-10 *(in millions)*
Proved developed producing	48,096	1,217	1,424	63,942	38.4%	$ 171.0
Proved developed non-producing	12,229	186	474	16,189	9.7%	24.1
Proved undeveloped	75,350	761	1,075	86,367	51.9%	44.6
Total	135,675	2,164	2,973	166,498	100.0%	$ 239.7

Our estimated net proved reserves as of December 31, 2010, were approximately 81% natural gas, 11% natural gas liquids and 8% crude oil and condensate.

Our average proved reserves-to-production ratio, or average reserve life, is approximately 12.9 years based on our proved reserves as of December 31, 2010 and production for the twelve months ended December 31, 2010. During 2010, 11 gross (4.5 net) operated and non-operated wells were drilled, 8 of which were successful. In 2011, we currently expect to drill 13 gross (7.9 net) wells, two of which are already in progress. Also, as of December 31, 2010, we had identified 82 proved undeveloped drilling locations and 778 other unproved drilling locations.

Proved Developed Reserves

Total proved developed reserves increased from 68.6 Bcfe at December 31, 2009 to 80.1 Bcfe at December 31, 2010. The change in proved developed reserves was attributable to 18.4 Bcfe of new reserves added from drilling and 6.0 Bcfe from positive performance revisions, offset in part by 12.9 Bcfe from 2010 production.

Proved Undeveloped Reserves

From December 31, 2009 to December 31, 2010, total proved undeveloped reserves increased from 28.9 Bcfe to 86.4 Bcfe. The increase in proved undeveloped reserves was attributable to 51.3 Bcfe from 2010 drilling and 6.1 Bcfe from positive performance revisions.

All of our undeveloped locations have been added within the last five years, almost half of which were added in May 2007 with our acquisition of Gulf Coast assets from EXCO. We believe our financial resources allow us the flexibility to drill all of the remaining undeveloped locations within a five year period from the time the locations were acquired.

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 Standards Board. Future net cash flow represents future gross cash flow from the production and sale of proved reserves, net of crude oil, natural gas and natural gas liquids 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. Future income taxes were estimated using future cash inflows, future tax depletion expense on existing producing properties and available net operating loss carryforwards that existed at year end for all years reported. At December 31, 2009, the future pretax net cash flows from our proved oil and gas reserves are estimated to be less than the sum of the tax basis of the applicable producing properties and our available net operating loss (*"NOLs"*) carryforward; therefore, there was zero future tax benefit or expense at December 31, 2009. We believe it is more likely than not that all of our total available NOLs will be realized within the appropriate carryforward period. Our operations and all NOLs are attributable to our oil and gas assets. We cannot assure you that the proved reserves will all be developed within the periods used in the calculations or that those prices and costs will remain constant. A standardized measure of discounted future net cash flows is not required to be presented for interim financial presentation dates.

	2010	**2009**	**2008**
Future cash inflows	$ 860,655,250	$ 475,007,800	$ 749,121,400
Future production and development costs			
Production	(218,221,203)	(156,581,500)	(214,969,100)
Development	(195,819,078)	(55,021,500)	(86,068,300)
Future cash flows before income taxes	446,614,969	263,404,800	448,084,000
Future income taxes	(37,624,289)	—	(46,695,950)
Future net cash flows after income taxes	408,990,680	263,404,800	401,388,050
10% annual discount for estimated timing of cash flows	(182,476,004)	(86,982,100)	(140,485,818)
Standardized measure of discounted future net cash flows	$ 226,514,676	$ 176,422,700	$ 260,902,233

Significant Properties

Summary proved reserve information for our properties, by region, with proved reserves is provided below as of December 31, 2010.

	Proved Reserves				PV-10 (1)
Regions	Crude Oil	Natural Gas	Natural Gas Liquids	Total	Amount
	(MBbl)	(MMcf)	(MBbl)	(MMcfe)	($000)
Southeast Texas	1,148	16,174	867	28,262	$ 108,945
South Texas	651	54,481	2,106	71,024	100,706
East Texas	—	59,336	—	59,336	13,734
Colorado & Other	365	5,684	—	7,876	16,336
Total	2,164	135,675	2,973	166,498	$ 239,721

(1) Under new SEC rules, prices used in determining our proved reserves as of December 31, 2010 and 2009 are based upon an unweighted 12-month first day of the month average price per MMBtu (Henry Hub spot) of natural gas and per barrel of oil (West Texas Intermediate posted). All prices are adjusted for quality, energy content, transportation fees and regional price differentials in determining proved reserves.

Production, Price and Cost History

See "Part I, Item 7.-Management's Discussion and Analysis of Financial Condition and Results of Operations."

Productive Wells

The following table shows the number of producing wells we owned by location at December 31, 2010:

	Crude Oil		Natural Gas	
	Gross Wells	Net Wells	Gross Wells	Net Wells
Southeast Texas	16	7.2	56	31.6
South Texas	15	4.2	265	142.1
East Texas	—	—	4	2.1
Colorado & Other	28	17.1	26	6.2
Total	59	28.5	351	182.0

In addition, as of December 31, 2010, we had 159 inactive wells and 16 salt water disposal wells.

Developed and Undeveloped Acreage

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 natural gas, crude oil and natural gas liquids. 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. The following table shows the approximate developed and undeveloped acreage that we have an interest in, by location, at December 31, 2010.

	Developed		Undeveloped	
	Gross Acres	Net Acres	Gross Acres	Net Acres
Southeast Texas	20,979	11,260	4,919	3,331
South Texas	77,630	42,831	11,662	8,474
East Texas	2,587	1,686	15,626	11,073
Colorado & Other	10,550	5,716	9,560	6,692
Total	111,746	61,493	41,767	29,570

Drilling Results

The following table shows the results of the wells drilled and completed for operated and non-operated properties for each of the last three fiscal years ended December 31, 2010. No crude oil wells were drilled during this time period.

	2010	**2009**	**2008**
Gross Gas Wells			
Development	9	5	18
Exploratory	1	1	5
Dry	1	1	1
Total	11	7	24
Net Gas Wells			
Development	3.91	2.00	10.37
Exploratory	—	0.52	1.00
Dry	0.62	0.39	0.20
Total	4.53	2.91	11.57

At December 31, 2010, we had two wells in progress. All dry wells drilled in the last three years were development wells.

Costs Incurred

The following table shows the costs incurred in our crude oil and gas producing activities for the past three years ended December 31, 2010:

	2010	2009	2008
Property Acquisitions:			
Proved	$ —	$ (493,532)	$ 60,765,315
Unproved	5,774,043	1,833,949	57,203,337
Development Costs	47,973,323	11,398,237	86,685,192
Exploration Costs	2,000,941	11,815,450	2,520,389
Total	$ 55,748,307	$ 24,554,104	$ 207,174,233

These costs include crude oil and gas property acquisition, exploration and development activities regardless of whether the costs were capitalized or charged to expense, including lease rental expenses and geological and geophysical expenses and changes to the long-lived asset related to our asset retirement obligation.

Property Dispositions

The following table shows oil and gas property dispositions for the past three years ended December 31, 2010:

	2010	2009	2008
Oil and gas properties	$ 2,601,997	$ 42,995,459	$ 21,765,688
Accumulated DD&A	(1,406,066)	(23,158,221)	(1,659,588)
Oil and gas properties, net	$ 1,195,931	$ 19,837,238	$ 20,106,100

The dispositions resulted in a net loss of $1.1 million, $6.8 million and a net gain of $15.2 million for 2010, 2009 and 2008, respectively.

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. During the second quarter of 2009, holders of oil and gas leases in East Texas (Haynesville Shale) filed two causes of action against us alleging breach of contract for not paying lease bonuses on certain oil and gas leases taken by our leasing agent. The damages alleged are approximately $2.4 million and we have received approximately $300,000 in written demands from other holders of leases in this area that we believe may contemplate legal proceedings. We are vigorously defending these lawsuits, and believe we have meritorious defenses. We do not believe that these claims will have a material adverse effect on our business, financial position, results of operations or cash flows, although we cannot guarantee that a material adverse effect will not occur.

In November 2010, we were named in a lawsuit filed by a current non-operating working interest partner that asserts that he owns a larger working interest in a field than previously recognized by us, and by predecessor operators to which we have granted indemnification rights. In dispute is whether ownership rights in specific depths were transferred through a number of decade-old poorly documented transactions. The maximum amount asserted in the suit filed could be determined at up to $4.7 million. We are vigorously defending this lawsuit and believe we have meritorious defenses. We currently do not believe that this claim will have a material adverse effect on our business, financial position, results of operations or cash flows, although we cannot guarantee that a material adverse effect will not occur.

PART II

ITEM 5. MARKET FOR OUR COMMON STOCK

Effective December 17, 2009, our common stock began trading on the NASDAQ Global Market under the symbol “CXPO.” Prior to that date, our common stock was traded on the Over-the-Counter Bulletin Board (the “OTCBB”) under the symbol “CXPO.OB.”

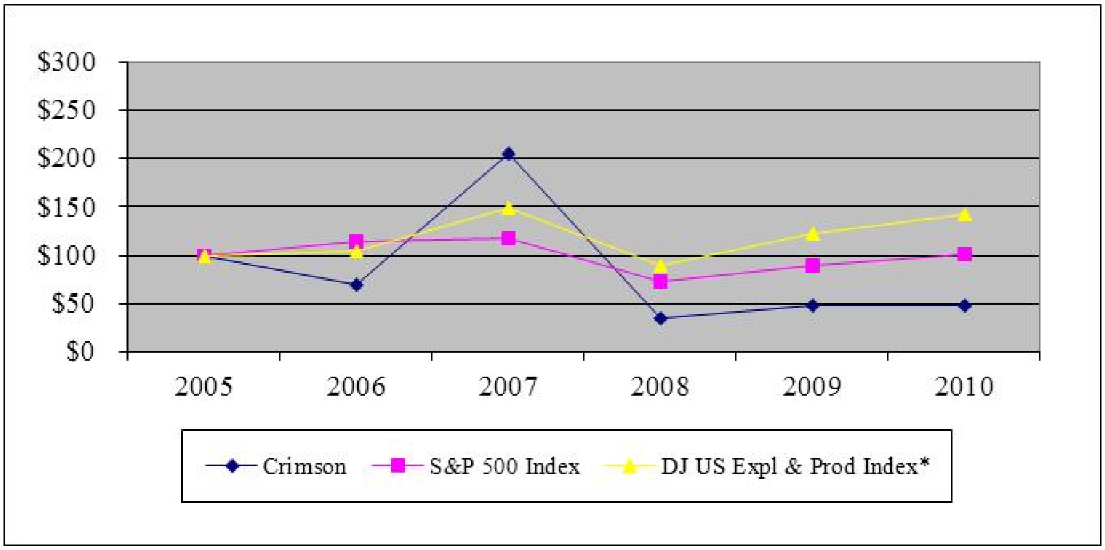
The following table sets forth the range of high and low bid quotation prices per share of our common stock as reported by NASDAQ beginning with the fourth quarter 2009. The third quarter 2009 and prior were reported by the OTCBB. The quotations reflect inter-dealer prices, without retail mark-up, mark-down or commissions, and may not represent actual transactions.

	High	Low
2010		
First Quarter	$ 4.74	$ 2.58
Second Quarter	4.00	2.50
Third Quarter	3.24	2.15
Fourth Quarter	4.53	2.50
2009		
First Quarter	$ 4.60	$ 0.80
Second Quarter	4.65	1.75
Third Quarter	4.30	2.26
Fourth Quarter	8.25	3.57

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, 2010 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. The comparison assumes $100 was invested on December 31, 2005 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, 2005	$	100.00	$	100.00	$	100.00
December 31, 2006	$	69.44	$	113.62	$	104.64
December 31, 2007	$	204.44	$	117.63	$	149.23
December 31, 2008	$	34.44	$	72.36	$	88.60
December 31, 2009	$	48.67	$	89.33	$	123.16
December 31, 2010	$	47.33	$	100.75	$	142.59

General

The following descriptions are summaries of material terms of our common stock, preferred stock, certificate of incorporation and bylaws. This summary is qualified by reference to our certificate of incorporation, bylaws and the designations of our preferred stock, which are filed as exhibits to this Annual Report on Form 10-K, and by the provisions of applicable law.

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 9, 2011, there were approximately 45.2 million shares of Common Stock issued and outstanding and held by approximately 245 record holders. On December 22, 2009, all shares of preferred stock, including accumulated dividends, were converted into Common Stock in conjunction with our equity offering. Continental Stock Transfer & Trust Company, 17 Battery Place, New York, NY 10004, (212) 509-4000 is our transfer agent for our Common Stock.

Holders of Common Stock are entitled to one vote for each share held on record on each matter submitted to a vote of stockholders 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 plurality of the outstanding shares of the Common Stock have the ability to elect all of the directors.

Holders of Common Stock have no preemptive or other rights to subscribe for shares. Holders of Common Stock are entitled to such dividends as may be declared by the Board out of funds legally available therefor. Our revolving credit agreement and second lien credit agreement each contain customary covenants restricting our ability to pay dividends. 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 stockholder 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. Any preferred stock that might be issued would be senior to our Common Stock regarding liquidation. The holders of the preferred stock do not have voting rights 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. On December 22, 2009, all outstanding shares, and accumulated dividends, of preferred stock that had not previously converted were converted into Common Stock in conjunction with our public offering of Common Stock.

Share-Based Compensation

On February 28, 2005, we established our 2005 Stock Incentive Plan (*"2005 Plan"*) and authorized the issuance of up to approximately 2.9 million shares of Common Stock pursuant to awards under the plan. In the third quarter 2008, our Board of Directors and a majority of our stockholders approved an amendment and restatement of our 2005 Stock Incentive Plan that provided for an increase in the number of shares of Common Stock available for award under our 2005 Stock Incentive Plan to approximately 3.9 million shares. We also issued 250,000 shares of restricted Common Stock to our executive officers outside of these plans. Approximately 1.7 million (1.3 million vested) stock options and 1.3 million unvested restricted shares were outstanding at December 31, 2010. Option awards outstanding have exercise prices ranging from $2.33 to $13.25 per share. In 2010 and 2009, respectively, 326,364 and 127,243 shares of restricted Common Stock vested, of which 33,600 and 40,921 shares were withheld by us to satisfy the employees' tax liability resulting from the vesting of these shares, as provided for in the restricted stock agreement, with the remaining shares being released to the employees and associated directors. At December 31, 2010, we had approximately 0.4 million shares of Common Stock available for future grant under the 2005 Plan.

Recent Sales of Unregistered Securities

As shown in the table below, during 2010, 2009 and 2008 we issued Common Stock not registered under the Securities Act of 1933 (the "Act"), 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	Class	Holder(s)	Underlying Shares	Exercise/ Conversion Price	Consideration
12/22/2010	Common Stock	ACEC	1,750,000	$ 5.00	Private Placement
10/26/2010	Common Stock	ACEC	4,250,000	$ 5.00	Private Placement
12/22/2009	Common Stock	Existing Stockholders	11,800,735	$ 5.00	Series G Preferred Stock Conversion
12/22/2009	Common Stock	Existing Stockholders	300,001	$ 3.50	Series H Preferred Stock Conversion
7/11/2008	Common Stock	Existing Stockholders	14,286	$ 9.00	Series H Preferred Stock Conversion
2/7/2008	Common Stock	Existing Stockholder	34,821	$ 9.00	Series G 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, 2010. This data should be read in conjunction with our Consolidated Financial Statements and the accompanying notes in "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,				
	2010	**2009**	**2008**	**2007**	**2006**
Statement of Operations Data					
Operating revenues	$ 96,541,967	$112,447,646	$186,768,273	$109,543,208	$ 21,659,481
Income (loss) from operations [1]	(14,314,897)	(387,836)	46,095,294	33,616,299	(2,458,685)
Net income (loss)	(30,844,897)	(34,069,990)	46,203,218	(430,517)	1,858,944
Dividends on preferred stock	—	(4,522,645)	(4,234,050)	(4,453,872)	(3,648,925)
Net income (loss) available to common stockholders	(30,844,897)	(38,592,635)	41,969,168	(4,884,389)	(1,789,981)
Net income (loss), per share					
Basic	$ (0.78)	$ (4.91)	$ 7.81	$ (1.13)	$ (0.55)
Diluted	$ (0.78)	$ (4.91)	$ 4.46	$ (1.13)	$ (0.55)
Weighted average shares outstanding					
Basic	39,397,486	7,861,054	5,371,377	4,330,282	3,231,000
Diluted	39,397,486	7,861,054	10,360,348	4,330,282	3,231,000

(1) Non-cash equity-based compensation charges were $1.8 million, $2.4 million and $5.4 million, in 2010, 2009 and 2008, respectively.

	Year Ended December 31,				
	2010	**2009**	**2008**	**2007**	**2006**
Balance Sheet Data					
Current assets	$ 27,562,216	$ 24,710,943	$ 46,347,553	$ 36,481,565	$ 4,231,983
Total assets	412,686,826	424,804,034	511,545,789	398,935,074	84,702,722
Current liabilities	47,370,072	33,486,034	83,989,610	48,879,245	10,932,155
Noncurrent liabilities	181,785,783	208,587,112	305,933,376	280,402,748	12,444,784
Stockholders' equity	183,530,971	182,730,888	121,622,803	69,653,081	61,325,783

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

You should read the following discussion of our results of operations and financial condition with the "Selected Historical Consolidated Financial Data" and the historical financial statements and related notes included elsewhere in this Annual Report. This discussion contains forward-looking statements and involves numerous risks and uncertainties, including, but not limited to, those described in the "Risk Factors" section of this Annual Report. Actual results may differ materially from those contained in any forward-looking statements.

Overview

Crimson is an independent energy company engaged in the acquisition, exploitation, exploration and development of natural gas and crude oil properties. We have historically focused our operations in the onshore U.S. Gulf Coast and South Texas regions, which are generally characterized by high rates of return in known, prolific producing trends. We have recently expanded our strategic focus to include longer reserve life resource plays that we believe provide significant long-term growth potential in multiple formations.

We intend to grow reserves and production by developing our existing producing property base, developing our East Texas and South Texas resource potential, and pursuing opportunistic acquisitions in areas where we have specific operating expertise. We have developed a significant project inventory associated with our existing property base. Our technical team has a successful track record of adding reserves through the drillbit. Since January 2008 and through December 2010, we have drilled 42 gross (19.0 net) wells with an overall success rate of 93%. At December 31, 2010, we had two wells in progress.

As of December 31, 2010, our proved reserves, as estimated by our independent reserve engineering firm, Netherland, Sewell & Associates, Inc., in accordance with reserve reporting guidelines mandated by the SEC, were 166.5 Bcfe, consisting of 135.7 Bcf of natural gas and 5.1 MMBbl of crude oil, condensate and natural gas liquids with a PV-10 of $239.7 million. As of December 31, 2010, 81% of our proved reserves were natural gas, 48% were proved developed and 89% were attributed to wells and properties operated by us. During 2010 we grew proved reserves from 97.5 Bcfe at December 31, 2009 to 166.5 Bcfe at December 31, 2010.

Recent Developments

New Second Lien Term Loan Facility

Effective December 27, 2010, we entered into a new second lien credit agreement providing for a five-year term loan in the principal amount of $175.0 million. Proceeds from the new term loan were used to retire all $150.0 million principal amount of its existing second lien term loan at par plus accrued interest, to pay off a $2.0 million subordinated promissory note, to pay related fees and expenses, and to use the remainder to substantially reduce outstanding borrowings under our first lien revolving bank credit facility. See "—Liquidity and Capital Resources—Capital resources."

Amendment to Revolving Credit Agreement

Effective December 27, 2010, we entered into a sixth amendment to our senior secured revolving credit agreement. This amendment provides, among other things, for: (i) an extension of the maturity date of our revolving credit facility to May 31, 2013; (ii) permitted issuance of the new second lien note and related guarantees, entering into the intercreditor agreement and related security documents, and the application of the net proceeds from this offering to pay off the $150.0 million existing second lien term loan and certain other debt; (iii) a reduction of the borrowing base by 25% of the principal amount in excess of $150.0 million of the new second lien notes offered and issued hereby; (iv) a change in the maximum leverage ratio (total consolidated debt to adjusted EBITDAX, as defined in the credit agreement); (v) a maximum senior leverage ratio (total borrowings and letter of credit commitments under the revolving credit facility to adjusted EBITDAX, as defined in the credit agreement); and (vi) a change in the minimum interest coverage ratio (adjusted EBITDAX to interest expense).

Our current borrowing base under our revolving credit facility of $88.75 million is limited unless and until we enter into additional hedging agreements that would add an incremental $3.0 million in discounted present value to our reserve base. See "Management's Discussion and Analysis of Financial Condition and Results of Operations—Liquidity and Capital Resources—Capital Resources."

Equity Issuance and Appointment of Director

On December 22, 2010, we completed a private placement transaction with America Capital Energy Corporation ("*ACEC*") and announced the appointment of Mr. Ni Zhaoxing to the board of directors in connection with the completion of this transaction. In the first step of the transaction, we issued 4,250,000 shares of common stock to ACEC on October 24, 2010 for $21.25 million and in the second step of the transaction we issued 1,750,000 shares of preferred stock for $8.75 million. In connection with the designation of Mr. Ni to the board of directors, the issued and outstanding shares of preferred stock automatically converted into an equal number of shares of common stock, giving ACEC an aggregate ownership of approximately 13.4% of the outstanding shares of our common stock.

The common stock sold by us in this private placement transaction is not registered under the Securities Act of 1933, as amended (the "Securities Act"), or any state securities laws and may not be offered or sold in the United States absent registration or an applicable exemption from the registration requirements of the Securities Act and applicable state laws.

ACEC is the U.S. private equity investment subsidiary of Shanghai Zhong Rong Property Group, Ltd., a private multi-faceted Shanghai-based company with operations in real estate, energy, mining, commercial property management, and financial investments.

Option Exchange Program

On February 18, 2011, we completed an option exchange program (the "Exchange Program") pursuant to which we exchanged outstanding options, each representing the right to purchase shares of Common Stock, granted under 2005 Plan with an exercise price greater than $5.00 per share, vested and unvested (the "Eligible Options"), for new options to purchase Common Stock (the "New Options").

The Exchange Program was effected with certain employees, including each of our named executive officers. Under the Exchange Program, a total of 1,093,240 Eligible Options with a weighted average exercise price of $11.24 per share were exchanged for 1,093,240 New Options with an exercise price of $5.00 per share. The table below sets forth the number of Eligible Options exchanged for an equivalent number of New Options and the weighted average exercise price of such Eligible Options held by each of our named executive officers.

	Eligible Options	Weighted Average Exercise Price
Allan D. Keel	500,000	$11.97
E. Joseph Grady	225,000	$11.38
Thomas H. Atkins	38,300	$11.60
Jay S. Mengle	45,000	$11.60
Tracy Price	90,000	$11.60
Total	898,300	$11.75

The Closing Price of the Common Stock on February 22, 2011, the trading date immediately following the completion of the Exchange Program, was $3.98; therefore, under the terms of the Exchange Program, the exercise price of the New Options was fixed at $5.00 per share. All of the New Options are subject to a vesting schedule providing for 25% of the New Options to vest annually over the first four years following February 18, 2011.

Due to an annual limitation in the number of options to purchase Common Stock that may be issued under the 2005 Plan, Allan D. Keel, our Chief Executive Officer, was limited to exchanging only the portion of Eligible Options held by him that was not in excess of such annual limitation. We may offer to exchange at a later date the remaining 175,000 Eligible Options that are held by Mr. Keel, which have a weighted average exercise price of $9.70.

The fair value of the Eligible Options exchanged, calculated using the Black-Scholes valuation model, was $1.8 million immediately prior to the exchange. The fair value of the New Options was calculated at $2.7 million. Therefore, the $0.9 million incremental value of the New Options over the Eligible Options and the unrecognized compensation cost for the original award as of the exchange date of $0.2 million, or $1.1 million, is being amortized using the straight line method over the new vesting period of four years, or approximately $22,000 a month.

Results of Operations

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

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

Revenues

	2010	2009	Change	Percent Change
		(in millions, except percentages)		
Product Revenues:				
Natural gas sales	$ 59.9	$ 71.5	$ (11.6)	-16.2%
Crude oil sales	22.0	27.3	(5.3)	-19.4%
Natural gas liquids sales	14.0	13.0	1.0	7.7%
Product revenues	$ 95.9	$ 111.8	$ (15.9)	-14.2%

Natural Gas, Crude Oil and Natural Gas Liquids Sales. Revenues from the sale of natural gas, crude oil and natural gas liquids, net of the realized effects of our hedging instruments, were $95.9 million in 2010 compared to $111.8 million in 2009, a decrease primarily due to lower production.

	2010	2009	Change	Percent Change
Sales volumes:				
Natural gas (Mcf)	9,285,574	10,414,441	(1,128,867)	-10.8%
Crude oil (Bbl)	260,289	326,707	(66,418)	-20.3%
Natural gas liquids (Bbl)	346,327	426,095	(79,768)	-18.7%
Natural gas equivalents (Mcfe)	12,925,270	14,931,253	(2,005,983)	-13.4%

Sales volumes decreased to 12.9 Bcfe in 2010 from 14.9 Bcfe in 2009. On a daily basis we produced an average of 35,412 Mcfe in 2010 compared to an average of 40,908 Mcfe in 2009. Lower production volumes are primarily attributed to three factors: (i) the sale of our Southwest Louisiana properties in December 2009 (approximately 1,115,000 Mcfe for 2009); (ii) the loss of approximately 161,000 Mcfe resulting from the shut-in of our Liberty County fields for seven days in mid-June 2010 due to a purchaser pipeline rupture and for two weeks in April 2010 for purchaser plant maintenance; and (iii) natural field decline as a result of limited capital expenditure activity in 2009.

	2010	2009	Change	Percent Change
Average sales prices (before hedging):				
Natural gas (Mcf)	$ 4.35	$ 3.97	$ 0.38	9.6%
Crude oil (Bbl)	79.05	56.99	22.06	38.7%
Natural gas liquids (Bbl)	40.57	30.57	10.00	32.7%
Natural gas equivalents (Mcfe)	5.80	4.89	0.91	18.6%

	2010	2009	Change	Percent Change
Average sales prices (after hedging):				
Natural gas (Mcf)	$ 6.45	$ 6.86	$ (0.41)	-6.0%
Crude oil (Bbl)	84.61	83.51	1.10	1.3%
Natural gas liquids (Bbl)	40.57	30.57	10.00	32.7%
Natural gas equivalents (Mcfe)	7.42	7.49	(0.07)	-0.9%

Natural gas, crude oil and natural gas liquids prices are reported net of the realized effect of our hedging agreements. We realized gains of $1.4 million on our crude oil hedges and $19.5 million on our natural gas hedges in 2010, compared to realized gains of $8.7 million for crude oil hedges and $30.1 million for natural gas hedges in 2009.

Operating Overhead and Other Income. Revenues representing overhead cost reimbursements billed to working interest partners on operated properties were $0.6 million in both 2010 and 2009.

Costs and Expenses

Certain Operating Expenses:	2010	2009	Change	Percent Change
		(in millions, except percentages)		
Lease operating expenses	$ 15.0	$ 17.4	$ (2.4)	-13.8%
Production and ad valorem taxes	6.1	7.1	(1.0)	-14.1%
Exploration expenses	1.0	2.7	(1.7)	-63.0%
General and administrative [(1)]	18.7	16.4	2.3	14.0%
Operating expenses (cash)	40.8	43.6	(2.8)	-6.4%
Depreciation, depletion & amortization	45.0	53.3	(8.3)	-15.6%
Share-based compensation [(1)]	1.8	2.4	(0.6)	-25.0%
Certain operating expenses [(2)]	$ 87.6	$ 99.3	$ (11.7)	-11.8%

(1) Total general and administrative costs on the Consolidated Statements of Operations include share-based compensation
(2) Exclusive of impairment and abandonment of oil and gas properties and sales of assets

Selected Costs ($ per Mcfe):	2010	2009	Change	Percent Change
		(in millions, except percentages)		
Lease operating expenses	$ 1.16	$ 1.16	$ —	—
Production and ad valorem taxes	0.47	0.48	(0.01)	-2.1%
Exploration expenses	0.07	0.18	(0.11)	-61.1%
General and administrative [(1)]	1.45	1.10	0.35	31.8%
Operating expenses (cash)	3.15	2.92	0.23	7.9%
Depreciation, depletion & amortization	3.48	3.57	(0.09)	-2.5%
Share-based compensation [(1)]	0.14	0.16	(0.02)	-12.5%
Selected costs	$ 6.77	$ 6.65	$ 0.12	1.8%

(1) Total general and administrative costs on the Consolidated Statements of Operations include share-based compensation

Lease Operating Expenses. Lease operating expenses for 2010 were $15.0 million, compared to $17.4 million in 2009, an overall decrease, but comparable to the $14.5 million incurred in 2009 after adjustment for the Southwest Louisiana properties sold in December 2009.

Production and Ad Valorem Tax Expenses. Production and ad valorem tax expenses for 2010 were $6.1 million, compared to $7.1 million in 2009, a decrease resulting from lower production in 2010.

Exploration Expenses. Exploration expenses were $1.0 million in 2010 compared to $2.7 million in 2009, a decrease resulting primarily from lower geological and geophysical expenses in 2010.

Depreciation, Depletion and Amortization ("DD&A"). DD&A expense for 2010 was $45.0 million compared to $53.3 million in 2009, a decrease due to lower production and a slightly lower per unit rate.

Impairment and Abandonment of Oil and Gas Properties. Non-cash impairment and abandonment of oil and gas properties for 2010 was $22.3 million compared to $6.7 million in 2009. In 2010, we incurred $0.5 million and $20.6 million in non-cash impairment expense for proved and unproved properties, respectively. We also incurred $1.2 million in abandonment expense related to unproved properties. In 2009, we incurred $3.2 million in non-cash impairment expense for proved properties and $2.5 million and $1.1 million in abandonment expense related to proved and unproved properties, respectively.

General and Administrative ("G&A") Expenses. G&A expenses were $20.5 million for 2010 compared to $18.8 million in 2009. The increase in G&A expenses is primarily a result of higher incentive compensation and higher legal fees in 2010. Included in G&A expense is a non-cash stock expense of $1.8 million ($0.14 per Mcfe) in 2010 compared to $2.4 million ($0.16 per Mcfe) in 2009.

Loss (Gain) on Sale of Assets. Loss on sale of assets for 2010 was $1.1 million compared to a loss on sale of assets of $6.8 million in 2009. The loss on sale of assets in 2010 was primarily the result of the sale of our Palo Pinto properties in Southeast Texas and the final settlement on the sale of our non-core Southwest Louisiana properties. The loss on sale of assets in 2009 was primarily the result of the sale of our non-core Southwest Louisiana properties.

Interest Expense. Interest expense was $22.3 million for 2010, compared to $23.2 million in 2009. Lower interest costs associated with lower overall debt balances in 2010 were substantially offset by higher interest rates on our second lien credit agreement. Total interest expense capitalized for 2010 and 2009 was $0.1 million and $25,000, respectively.

Other Financing Costs. Other financing costs were $4.3 million for 2010 compared with $3.3 million for 2009. These expenses are comprised primarily of the amortization of capitalized costs associated with our current and former credit agreements and of commitment fees related to the unused portion of the credit agreements. In 2010 we wrote off $2.0 million in debt issuance costs associated with the $150.0 million second lien credit facility that was paid off in December 2010. In 2009 we recorded $1.7 million in debt issuance costs for a $2.0 million unsecured promissory note issued in conjunction with a $10.0 million bridge loan that was paid off in December 2009.

Unrealized Gain (Loss) on Derivative Instruments. Unrealized gain or loss on derivative instruments is the change in the mark-to-market exposure under our commodity price hedging instruments and our interest rate swaps. This non-cash unrealized loss was $6.5 million for 2010 compared with a loss of $23.9 million for 2009. Unrealized gain or loss will vary period to period, and will be a function of the hedges in place, the strike prices of those hedges, and the forward curve pricing of the commodities and interest rates being hedged.

Income Taxes. Our net loss before taxes was $47.5 million for 2010 compared with $50.8 million in 2009. After adjusting for permanent tax differences, we recorded an income tax benefit of $16.6 million for 2010, which is all deferred. After adjusting for permanent tax differences, we recorded an income tax benefit of $16.7 million for 2009, of which $0.1 million was current tax expense and $16.6 million was deferred. Our effective tax rates differ from the statutory rate of 35% primarily because of state and local taxes and the tax effects of permanent book-tax differences.

Dividends on Preferred Stock. Dividends on preferred stock were zero in 2010 compared with $4.5 million in 2009. All of the Series G and H Preferred Stock, including accrued dividends, were converted to Common Stock in December 2009 in conjunction with our Common Stock offering. Dividends in 2009 included $4.4 million on the Series G Preferred Stock and $0.1 million on the Series H Preferred Stock.

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

Revenues

	2009	2008	Change	Percent Change
		(in millions, except percentages)		
Product Revenues:				
Natural gas sales	$ 71.5	$ 116.4	$ (44.9)	-38.6%
Crude oil sales	27.3	41.9	(14.6)	-34.8%
Natural gas liquids sales	13.0	27.4	(14.4)	-52.6%
Product revenues	$ 111.8	$ 185.7	$ (73.9)	-39.8%

Natural Gas, Crude Oil And Natural Gas Liquids Sales. Revenues from the sale of natural gas, crude oil and natural gas liquids, net of the realized effects of our hedging instruments, declined to $111.8 million in 2009 compared to $185.7 million in 2008. The decrease in net revenues was primarily due to a decrease in production and realized commodity prices.

	2009	2008	Change	Percent Change
Sales volumes:				
Natural gas (Mcf)	10,414,441	13,135,509	(2,721,068)	-20.7%
Crude oil (Bbl)	326,707	498,143	(171,436)	-34.4%
Natural gas liquids (Bbl)	426,095	516,352	(90,257)	-17.5%
Natural gas equivalents (Mcfe)	14,931,253	19,222,479	(4,291,226)	-22.3%

Sales volumes decreased to 14.9 Bcfe in 2009 from 19.2 Bcfe in 2008. On a daily basis we produced an average of 40,908 Mcfe in 2009 compared to an average of 52,520 Mcfe in 2008. Production volumes decreased primarily due to natural field decline and limited production-enhancing capital expenditure activity in 2009.

	2009	2008	Change	Percent Change
Average sales prices (before hedging):				
Natural gas (Mcf)	$ 3.97	$ 8.92	$ (4.95)	-55.5%
Crude oil (Bbl)	56.99	101.13	(44.14)	-43.6%
Natural gas liquids (Bbl)	30.57	53.07	(22.50)	-42.4%
Natural gas equivalents (Mcfe)	4.89	10.14	(5.25)	-51.8%

	2009	2008	Change	Percent Change
Average sales prices (after hedging):				
Natural gas (Mcf)	$ 6.86	$ 8.86	$ (2.00)	-22.6%
Crude oil (Bbl)	83.51	84.03	(0.52)	-0.6%
Natural gas liquids (Bbl)	30.57	53.07	(22.50)	-42.4%
Natural gas equivalents (Mcfe)	7.49	9.66	(2.17)	-22.5%

Natural gas, crude oil and natural gas liquids prices are reported net of the realized effect of our hedging agreements. We realized gains of $8.7 million on our crude oil hedges and $30.1 million on our natural gas hedges in 2009, compared to realized losses of $8.5 million for crude oil hedges and realized gains of $0.8 million for natural gas hedges in 2008.

Operating Overhead and Other Income. Revenues representing overhead cost reimbursements billed to working interest partners on operated properties decreased to $0.6 million in 2009 compared to $1.1 million in 2008 due to the one-time catch up in the third quarter 2008 on overhead billings.

Costs and Expenses

	2009	2008	Change	Percent Change
Certain Operating Expenses:		(in millions, except percentages)		
Lease operating expenses	$ 17.4	$ 20.8	$ (3.4)	-16.3%
Production and ad valorem taxes	7.1	16.3	(9.2)	-56.4%
Exploration expenses	2.7	2.6	0.1	3.8%
General and administrative (1)	16.4	17.0	(0.6)	-3.5%
Operating expenses (cash)	43.6	56.7	(13.1)	-23.1%
Depreciation, depletion & amortization	53.3	50.5	2.8	5.5%
Share-based compensation (1)	2.4	5.4	(3.0)	-55.6%
Certain operating expenses (2)	$ 99.3	$ 112.6	$ (13.3)	-11.8%

(1) Total general and administrative costs include share-based compensation on the Consolidated Statements of Operations
(2) Exclusive of impairment and abandonment of oil and gas properties and sales of assets

Selected Costs ($ per Mcfe):	2009	2008	Change	Percent Change
		(in millions, except percentages)		
Lease operating expenses	$ 1.16	$ 1.08	$ 0.08	7.4%
Production and ad valorem taxes	0.48	0.85	(0.37)	-43.5%
Exploration expenses	0.18	0.14	0.04	28.6%
General and administrative (1)	1.10	0.88	0.22	25.0%
Operating expenses (cash)	2.92	2.95	(0.03)	--1.0%
Depreciation, depletion & amortization	3.57	2.63	0.94	35.7%
Share-based compensation (1)	0.16	0.28	(0.12)	-42.9%
Selected costs	$ 6.65	$ 5.86	$ 0.79	13.5%

(1) Total general and administrative costs include share-based compensation on the Consolidated Statements of Operations

Lease Operating Expenses. Lease operating expenses for 2009 were $17.4 million, compared to $20.8 million in 2008, a decrease resulting from the implementation of cost reduction initiatives during 2009 and generally lower costs of goods and services in the industry.

Production and Ad Valorem Tax Expenses. Production and ad valorem tax expenses for 2009 were $7.1 million, compared to $16.3 million in 2008, a decrease resulting from lower production and lower prices in 2009.

Exploration Expenses. Total exploration expenses were $2.7 million in 2009 compared to $2.6 million in 2008. Exploration expenses include geological and geophysical costs, lease rentals and asset retirement obligation settlement adjustments.

Depreciation, Depletion and Amortization ("DD&A"). DD&A expense for 2009 was $53.3 million compared to $50.5 million in 2008, due to a higher DD&A rate resulting predominately from the effect of negative price-related reserve revisions offset by lower production in 2009.

Impairment and Abandonment of Oil and Gas Properties. Non-cash expense recorded for impairment and abandonment of oil and gas properties for 2009 was $6.7 million compared to $43.3 million in 2008. In 2009, we incurred $3.2 million in non-cash impairment expense for proved properties and $2.5 million and $1.1 million in abandonment expense related to proved and unproved properties, respectively. In 2008, we incurred $36.0 million in non-cash impairment expense for proved properties and $7.4 million in abandonment expense related to unproved properties.

General and Administrative ("G&A") Expenses. Our G&A expenses were $18.8 million for 2009 compared to $22.4 million in 2008. The reduction in G&A expenses is primarily a result of the implementation of cost reduction initiatives during 2009 and the decrease in non-cash stock expense of $2.4 million ($0.16 per Mcfe) in 2009 compared with $5.4 million ($0.28 per Mcfe) for 2008.

Loss (Gain) on Sale of Assets. Loss on the sale of assets for 2009 was $6.8 million compared to a gain on sale of assets of $15.2 million in 2008. The net loss on the sale of assets was primarily the result of the sale of our non-core Southwest Louisiana properties. The gain on the sale of assets in 2008 was primarily due to the disposition of our interest in the Barnett Shale Play in the first quarter 2008, which resulted in a gain of $15.6 million.

Interest Expense. Interest expense was $23.2 million for 2009, up from $21.1 million in 2008. Total interest expense increased primarily due to a higher debt balance on our revolving credit agreement and higher interest rates on our second lien credit agreement. Total interest expense capitalized for 2009 and 2008 was $25,000 and $0.9 million, respectively.

Other Financing Costs. Other financing costs were $3.3 million for 2009 compared with $1.5 million for 2008. These expenses are comprised primarily of the amortization of capitalized costs associated with our current and former credit agreements and of commitment fees related to the unused portion of the credit agreements. In 2009 we also fully amortized the $1.7 million in debt issuance costs associated with the $10.0 million bridge loan that was paid off in December 2009.

Unrealized Gain (Loss) on Derivative Instruments. Unrealized gain or loss on derivative instruments is the change in the mark-to-market exposure under our commodity price hedging instruments and our interest rate swaps. This non-cash unrealized loss was $23.9 million for 2009 compared with a non-cash unrealized gain of $49.4 million for 2008. Unrealized gain or loss will vary period to period, and will be a function of the hedges in place, the strike prices of those hedges, and the forward curve pricing of the commodities and interest rates being hedged.

Income Taxes. Our net loss before taxes was $50.8 million for 2009 compared to net income before taxes of $72.9 million in 2008. After adjusting for permanent tax differences, we recorded income tax benefit of $16.7 million for 2009, of which $0.1 million was current tax expense and $16.6 million was deferred. We recorded income tax expense of $26.7 million for 2008 of which $0.6 million was current and $26.1 million was deferred. Our effective tax rates differ from the statutory rate of 35% primarily because of state and local taxes and the tax effects of permanent book-tax differences.

Dividends on Preferred Stock. Dividends on preferred stock were $4.5 million in 2009 compared with $4.2 million in 2008. All of the Series G and H Preferred Stock, including accrued dividends, were converted to Common Stock in December 2009 in conjunction with our Common Stock offering. Dividends in 2009 included $4.4 million on the Series G Preferred Stock and $0.1 million on the Series H Preferred Stock.

Critical Accounting Policies and Estimates

The discussion and analysis of financial condition and results of our operations are based upon our consolidated financial statements, which have been prepared in accordance with accounting principles generally accepted in the United States. The preparation of these financial statements requires us to make estimates and assumptions that affect the reported amounts of assets, liabilities, revenues and expenses. Certain accounting policies involve judgments and uncertainties to such an extent that there is reasonable likelihood that materially different amounts could have been reported under different conditions or if different assumptions had been used. We evaluate such estimates and assumptions on a regular basis. We base our estimates on historical experience and various other assumptions that are believed to be reasonable under the circumstances, the results of which form the basis for making judgments about the carrying values of assets and liabilities that are not readily apparent from other sources. Actual results may differ from these estimates and assumptions used in preparation of our financial statements. Below, we have provided expanded discussion of the more significant accounting policies, estimates and judgments. We believe these accounting policies reflect the more significant estimates and assumptions used in preparation of our financial statements. Please read the notes to our audited consolidated financial statements included in this Annual Report for a discussion of additional accounting policies and estimates made by management.

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).

Revenue Recognition

We follow the "sales" method of accounting for natural gas, crude oil and natural gas liquids 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.

Depletion and Depreciation

The estimates of natural gas, crude oil and natural gas liquids reserves utilized in the calculation of depletion and depreciation are estimated in accordance with guidelines established by the Society of Petroleum Engineers, the SEC 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 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 natural gas, crude oil and natural gas liquids 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 natural gas, crude oil and natural gas liquids 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.

Impairment of Oil and Gas Properties

We assess our proved properties for possible impairment on an annual basis as a minimum, or as circumstances warrant, based on geological trend analysis, changes in proved reserves or relinquishment of acreage. When impairment occurs, the adjustment is recorded to accumulated depletion. See the discussion of impairment expenses in "Management's Discussion and Analysis of Financial Condition and Results of Operations."

Unproved Leasehold Costs

The costs of unproved leaseholds, including associated interest costs for the period activities that were in progress to bring projects to their intended use, are capitalized pending the results of exploration efforts. We regularly assess on a property-by-property basis the impairment of individual unproved properties whose acquisition costs are relatively significant. Unproved properties whose acquisition costs are not relatively significant are amortized in the aggregate over the lesser of three years or the average remaining lease term. As exploration work progresses and the reserves on significant properties are proven, capitalized costs of these properties will be subject to depreciation and depletion. If the exploration work is unsuccessful, the capitalized costs of the properties related to the unsuccessful work will be charged to exploration expense. The timing of any write-downs of these unproven properties, if warranted, depends upon the nature, timing and extent of future exploration and development activities and their results.

Asset Retirement Obligations

We recognize an estimated liability for the plugging and abandonment of our natural gas, crude oil and natural gas liquids 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, or 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 reserve 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 acquisitions and dispositions, 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.

Derivative Instruments

At the end of each reporting period we 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

Accounting Standards Not Yet Adopted

Various accounting standards and interpretations were issued in 2010 with effective dates subsequent to December 31, 2010. We have evaluated the recently issued accounting pronouncements that are effective in 2011 and believe that none of them will have a material effect on our financial position, results of operations or cash flows when adopted.

Further, we are closely monitoring the joint standard-setting efforts of the Financial Accounting Standards Board and the International Accounting Standards Board. There are a large number of pending accounting standards that are being targeted for completion in 2011 and beyond, including, but not limited to, standards relating to revenue recognition, accounting for leases, fair value measurements, accounting for financial instruments, disclosure of loss contingencies and financial statement presentation. Because these pending standards have not yet been finalized, at this time we are not able to determine the potential future impact that these standards will have, if any, on our financial position, results of operations or cash flows.

Commitments and Contingencies

The following table provides information about our obligations as of December 31, 2010:

	Long-term debt	Interest	Operating leases (2)	Asset retirements	Executive compensation	ASC Topic 740 (1)
2011	$ —	$ 22,371,458	$ 1,527,859	$ 718,742	$ 1,560,000	$ —
2012	—	22,371,458	1,448,744	326,958	82,417	—
2013	4,000,000	22,259,041	1,419,933	437,264	—	—
2014	—	22,178,819	118,328	401,632	—	—
2015	175,000,000	21,996,530	—	724,104	—	—
Thereafter	—	—	—	9,950,072	—	518,219
Total	$ 179,000,000	$ 111,177,306	$ 4,514,864	$ 12,558,772	$ 1,642,417	$ 518,219

(1) FASB ASC Topic 740 (previously reported as FASB Interpretation No. 48, "Accounting for Uncertainty in Income Taxes, An interpretation of FASB Statement No. 109"). We cannot predict at this time when this obligation may be required to be paid, if at all.

(2) Operating leases include contracts related to office space, compressors, vehicles, office equipment and other.

Liquidity and Capital Resources

Our primary cash requirements during the year are for capital expenditures, working capital, operating expenses, acquisitions and principal and interest payments on indebtedness. Our primary sources of liquidity are cash generated by operations and amounts available to be drawn under our revolving credit facility. To the extent our cash requirements exceed our sources of liquidity, we will be required to fund our cash requirements through other means, such as through debt and equity financing activities, asset monetization or the curtailment of capital expenditures.

Second Lien Credit Agreement

We entered into a new second lien credit agreement with Barclays Bank Plc, as agent, and the lender parties thereto which provided for term loans, made to us in a single draw, in an aggregate principal amount of $175 million on December 27, 2010. Our second lien credit agreement replaced our then existing $150 million second lien credit agreement with Credit Suisse, which was paid off in full and terminated at closing. Our second lien credit agreement matures on December 27, 2015. At December 31, 2010, we had a principal amount of $175.0 million outstanding under our second lien credit agreement, with a discount of $7.0 million using the estimated market value interest rate at the time of issuance, for a net balance of $168.0 million.

Equity Issuance

On December 22, 2010, we completed a private placement transaction with America Capital Energy Corporation (*"ACEC"*) and announced the appointment of Mr. Ni Zhaoxing to the board of directors in connection with the completion of this transaction. In the first step of the transaction, we issued 4,250,000 shares of common stock to ACEC on October 24, 2010 for $21.25 million and in the second step of the transaction we issued 1,750,000 shares of preferred stock for $8.75 million. In connection with the completion of the second and final step of the private placement and the designation of Mr. Ni to the board of directors, the issued and outstanding shares of preferred stock automatically converted into an equal number of shares of common stock, giving ACEC an aggregate ownership of approximately 13.4% of the outstanding shares of our common stock. We intend to use the net proceeds from the private placement for general corporate purposes, including the continued development of our significant inventory of drilling prospects.

Liquidity and cash flow

Our working capital deficit was $19.8 million as of December 31, 2010, compared to a working capital deficit of $8.8 million as of December 31, 2009, an increase due to a more active drilling program in 2010. The following table provides the components and changes in working capital as of December 31, 2010 and 2009, respectively.

	2010	2009	Change
		(in millions)	
Current assets			
Accounts receivable - net	$ 14.2	$ 14.8	$ (0.6)
Prepaid expenses	0.2	—	0.2
Derivative instruments	6.9	9.9	(3.0)
Deferred tax asset, net	6.3	—	6.3
Total current assets	27.6	24.7	2.9
Current liabilities			
Current portion of long-term debt	—	—	—
Accounts payable and accrued liabilities	43.6	29.1	14.5
Income tax payable	—	0.3	(0.3)
Asset retirement obligations	0.7	0.3	0.4
Derivative instruments	3.1	0.9	2.2
Deferred tax liability, net	—	2.9	(2.9)
Total current liabilities	47.4	33.5	13.9
Working capital (deficit)	$ (19.8)	$ (8.8)	$ (11.0)

The table below summarizes certain measures of liquidity and capital expenditures, as well as our sources of capital from internal and external sources, for the past three years ended December 31, 2010, 2009 and 2008.

	Year Ended December 31,		
	2010	2009	2008
Financial Measures		(in millions)	
Net cash provided by operating activities	$ 48.0	$ 9.7	$ 143.8
Net cash used in investing activities	(54.9)	(13.8)	(165.4)
Net cash provided by financing activities	6.9	4.2	16.7
Cash and cash equivalents	—	—	—
Capital expenditures, including acquisitions	54.7	21.4	200.3

Net cash provided by operating activities was $48.0 million for the twelve months ended December 31, 2010, compared to $9.7 million for the twelve months ended December 31, 2009, as 2009 was impacted by a $37 million reduction in working capital due to the satisfaction of high year end 2008 current liabilities related to an active late 2008 drilling program. During 2010, the net cash provided by operating activities, before changes in working capital, was $33.6 million compared with net cash provided by operating activities, before changes in working capital, of $46.8 million in 2009, a decrease resulting primarily from lower sales revenues from lower production.

Net cash used in investing activities, which consists primarily of capital expenditures on oil and gas drilling projects and leasehold acquisitions, was $54.9 million for the twelve months ended December 31, 2010 compared to $13.8 million for the twelve months ended December 31, 2009. Net cash used for investing activities during 2009 was expenditures of $21.4 million related to our 2009 capital program, offset in part by $7.3 million in cash proceeds from the sale of certain Southwest Louisiana properties.

Net cash provided by financing activities was $6.9 million for the twelve months ended December 31, 2010 compared to $4.2 million for the twelve months ended December 31, 2009. Net cash provided by financing activities during 2010 was primarily the result of net proceeds of $30.0 million from the sale of common stock, offset in part by net repayments of outstanding borrowings of $21.0 million under our revolving credit agreement. Net cash provided by financing activities during 2009 was primarily the result of net proceeds of $92.9 million from the sale of stock, offset by net repayments of outstanding borrowings of $85.7 million under our revolving credit agreement.

Capital resources

We have a revolving credit agreement with Wells Fargo Bank, National Association ("*Wells Fargo Bank*"), as agent, and the lender parties thereto that currently provides for an $88.75 million borrowing base, based on our current proved crude oil and natural gas reserves. The borrowing base is periodically determined by our banks based primarily upon an evaluation of our proved oil and gas reserves, which can be impacted by changes in commodity prices including hedged positions, drilling costs and results, production, and other revisions, additions and sales of reserves. The borrowing base is subject to semi-annual redeterminations, although our lenders may elect to make one additional unscheduled redetermination between scheduled redetermination dates. All principal amounts, together with all accrued and unpaid interest owed under the agreement, will be due and payable in full on May 31, 2013 under the sixth amendment to the credit agreement. The credit agreement also provides for the issuance of letters-of-credit up to a $5.0 million sub-limit.

Advances under our revolving credit agreement are in the form of either base rate loans or LIBOR loans. The interest rate on the base rate loans fluctuates based upon the higher of the lender's "prime rate" and the Federal Funds rate. The interest rate on the LIBOR loans fluctuates based upon the rate at which Eurodollar deposits in the LIBOR market are quoted for the maturity selected. Pursuant to an amendment to our revolving credit agreement, dated July 31, 2009, the applicable margin was increased from between 1.25% and 2.00% to between 2.75% and 3.50%, for LIBOR loans, and from zero and 0.50% to between 1.50% and 2.00%, for base rate loans. The specific applicable interest margin is determined by, in each case, the percent of the borrowing base utilized at the time of the credit extension. LIBOR loans of one, two, three and six months may be selected. Pursuant to that same amendment, the commitment fee payable on the unused portion of our borrowing base was increased from 0.375% to 0.50%, which fee accrues and is payable quarterly in arrears.

At March 9, 2011, we had zero outstanding under our revolving credit agreement, with full availability under our revolving credit agreement of $88.75 million.

We also have a new second lien credit agreement with Barclays Bank Plc, as agent, and the lender parties thereto which provided for term loans, made to us in a single draw, in an aggregate principal amount of $175.0 million. Our second lien credit agreement replaced our then existing $150.0 million second lien credit agreement with Credit Suisse, which was paid off in full and terminated on December 27, 2010. Our second lien credit agreement matures on December 27, 2015.

Advances under our new second lien credit agreement are in the form of either base rate loans or LIBOR loans. The interest rate on the base rate loans fluctuates based upon the greatest of (i) 4.00% per annum, (ii) the "prime rate", (iii) the Federal Funds Effective Rate plus ½ of 1% and (iv) the LIBOR rate for a one month interest period plus 1.00%. The applicable margin for base rate loans is 8.50%. The interest rate on the LIBOR loans fluctuates based upon the higher of (i) 3.0% per annum and (ii) the LIBOR rate per annum. The applicable margin for LIBOR loans is 9.50%.

Our revolving credit agreement and second lien credit agreement are secured by liens on substantially all of our assets, including the capital stock of our subsidiaries. The liens securing the obligations under our second lien credit agreement are junior to those under our revolving credit agreement. Unpaid interest is payable under our credit agreements as borrowings mature and renew.

We utilize financial commodity price hedge instruments to minimize exposure to declining prices on our crude oil and natural gas liquids production. We currently have 12.5 Bcfe of equivalent production hedged for 2011 and 2012, consisting of 6.0 Bcf of natural gas hedges, 225.8 MBbl of crude oil hedges and 2.1 million gallons of natural gas liquids hedges in place for 2011, at average floor prices of $6.31/MMBtu, $77.83/Bbl and $7.32/gallon, respectively and 3.8 Bcf of natural gas hedges and 175.2 MBbl of crude oil hedges in place for 2012 at average floor prices of $5.00/MMBTU and $84.99/Bbl, respectively. We used a series of swaps and costless collars to accomplish our commodity hedging position. We also constructively fixed the base LIBOR on $150.0 million of our variable rate debt by entering into interest rate swaps at a weighted average swap price of 2.9%.

At March 9, 2011, we had a principal amount of $175.0 million outstanding under our second lien credit agreement, with a discount of approximately $7.0 million using the estimated market value interest rate at the time of issuance, for a net balance of $168.0 million.

Covenant compliance

Our credit agreements require us to maintain compliance with specified financial ratios and satisfy certain financial condition tests. Our compliance with these covenants is tested each quarter. At December 31, 2010, we were in compliance with the covenants under our revolving credit agreement and second lien credit agreements. See Note 9 —"Debt" for a more detailed description of terms and provisions of our credit agreements.

Future capital requirements

Our future natural gas, crude oil and natural gas liquids reserves and production, and therefore our cash flow and results of operations, are highly dependent on our success in efficiently developing and exploiting our current reserves and economically finding or acquiring additional recoverable reserves. We intend to grow our reserves and production by further exploiting our existing property base through drilling opportunities identified in our new resource plays in East and South Texas and in our conventional inventory. We expect to focus the majority of our drilling activity over the next several years on continued development of our East Texas and South Texas resource plays while we continue the development and exploitation of our core legacy properties in the South Texas and Gulf Coast areas. We anticipate that acquisitions, including those of undeveloped leasehold interests, will continue to play a role in our business strategy as those opportunities periodically arise from time to time. While there are currently no unannounced agreements for the acquisition of any material businesses or assets, such transactions can be effected quickly and could occur at any time.

We believe that our internally generated cash flow, combined with access to our revolving credit agreement, will be sufficient to meet the liquidity requirements necessary to fund our daily operations and planned capital development and to meet our debt service requirements for the next 12 months. Our ability to execute on our growth strategy will be determined, in large part, by our cash flow and the availability of debt and equity capital at that time. Any decision regarding a financing transaction, and our ability to complete such a transaction, will depend on prevailing market conditions and other factors. Our ability to continue to meet our liquidity requirements and execute on our growth strategy can be impacted by economic conditions outside of our control, such as the recent disruption in the capital and credit markets, as well as continued commodity price volatility, which could, among other things, lead to a decline in the borrowing base under our revolving credit agreement in connection with a borrowing base redetermination. In such case, we may be required to seek other sources of capital earlier than anticipated. Restrictions in our credit agreements may impair our ability to access other sources of capital, and access to additional capital may not be available on terms acceptable to us or at all. See "Risk Factors—Recent market events and conditions, including disruptions in the U.S. and international credit markets and other financial systems and the deterioration of the U.S. and global economic conditions, could, among other things, impede access to capital or increase the cost of capital, which would have an adverse effect on our ability to fund our working capital and other capital requirements," "Risk Factors—Our development and exploration operations, including on our East Texas resource play acreage, require substantial capital, and we may be unable to obtain needed capital or financing on satisfactory terms, which could lead to a loss of properties and a decline in our natural gas, crude oil and natural gas liquids reserves" and "Management's Discussion and Analysis of Financial Condition and Results of Operations."

Our 2011 capital budget is currently forecast to be approximately $60 million, exclusive of acquisitions on our resource plays and conventional producing properties. We plan to drill 13 gross (7.9 net) wells in 2011, two of which are already in progress. The actual number of wells drilled and the amount of our 2011 capital expenditures will depend on market conditions, availability of capital and drilling and production results.

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 natural gas, crude oil and natural gas liquids prices realized over the last three years. Average prices per Mcf equivalent, computed by converting crude oil and natural gas liquids production to natural gas equivalents at the rate of 6 Mcf per barrel, indicate the composite impact of changes in natural gas, crude oil and natural gas liquids prices.

	Average Prices(1)			
	Natural Gas (per Mcf)	Crude Oil (per Bbl)	Natural Gas Liquids (per Bbl)	Per Equivalent Mcf
2010				
First	$ 6.96	$ 83.77	$ 46.25	$ 7.90
Second	6.91	84.66	38.99	7.77
Third	6.47	84.76	34.60	7.21
Fourth	5.74	85.02	43.64	7.02
2009				
First	$ 6.71	$ 77.18	$ 22.51	$ 7.08
Second	6.71	80.62	27.37	7.29
Third	6.92	87.85	31.50	7.60
Fourth	7.20	92.19	42.87	8.15
2008				
First	$ 8.39	$ 78.62	$ 57.18	$ 9.39
Second	10.23	95.52	55.73	10.94
Third	9.68	92.54	63.49	10.67
Fourth	7.20	68.42	28.84	7.52

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

Off Balance Sheet Arrangements

We may enter into off-balance sheet arrangements that can give rise to off-balance sheet obligations. As of December 31, 2010, the primary off-balance sheet arrangements that we have entered into included drilling rig contracts and operating lease agreements, all of which are customary in the oil and gas industry. Other than the off-balance sheet arrangements listed above, we have no other arrangements that are reasonably likely to materially affect our liquidity or availability of or requirements for capital resources.

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 and are incorporated herein by reference.

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, 2010, 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, 2010 is in "Item 8. Financial Statements and Supplementary Data" in Part II of this Annual Report on Form 10-K and is incorporated herein by reference.

Our management assesses the effectiveness of our internal control over financial reporting using criteria set forth in Internal Control – Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission.

This Annual Report does not include an attestation report of our registered public accounting firm regarding internal control over financial reporting. Management's report was not subject to attestation by our independent registered public accounting firm pursuant to rules of the SEC that permit us to provide only management's report in this Annual Report.

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, 2010.

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, 2010.

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, 2010.

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, 2010.

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, 2010.

GLOSSARY OF SELECTED TERMS

The following is a description of the meanings of some of the oil and gas industry terms used in this Annual Report.

2D seismic or *3D seismic*. Geophysical data that depict the subsurface strata in two dimensions or three dimensions, respectively. 3-D seismic typically provides a more detailed and accurate interpretation of the subsurface strata than 2-D seismic.

Bbl. One stock tank barrel, or 42 U.S. gallons liquid volume, in reference to crude oil or other liquid hydrocarbons.

Bcf. Billion cubic feet of natural gas.

Bcfe. Billion cubic feet equivalent, determined using the ratio of six Mcf of natural gas to one Bbl of crude oil, condensate or natural gas liquids.

Btu or British thermal unit. The quantity of heat required to raise the temperature of one pound of water by one degree Fahrenheit.

Completion. The process of treating a drilled well followed by the installation of permanent equipment for the production of natural gas or oil, or in the case of a dry hole, the reporting of abandonment to the appropriate agency.

Condensate. Liquid hydrocarbons associated with the production of a primarily natural gas reserve.

Developed acreage. The number of acres that are allocated or assignable to productive wells or wells capable of production.

Development well. A well drilled into a proved natural gas or oil reservoir to the depth of a stratigraphic horizon known to be productive.

Dry hole. A well found to be incapable of producing hydrocarbons in sufficient quantities such that proceeds from the sale of such production exceed production expenses and taxes.

Exploratory well. A well drilled to find a new field or to find a new reservoir in a field previously found to be productive of natural gas or crude oil in another reservoir.

Field. An area consisting of either a single reservoir or multiple reservoirs all grouped on or related to the same individual geological structural feature and/or stratigraphic condition.

Gross acres or gross wells. The total acres or wells, as the case may be, in which a working interest is owned.

MBbls. Thousand barrels of crude oil or other liquid hydrocarbons.

Mcf. Thousand cubic feet of natural gas.

Mcfe. Thousand cubic feet equivalent, determined using the ratio of six Mcf of natural gas to one Bbl of crude oil, condensate or natural gas liquids.

MMBbls. million barrels of crude oil or other liquid hydrocarbons.

MMBtu. million British Thermal Units.

MMcf. million cubic feet of natural gas.

MMcfe. million cubic feet equivalent, determined using the ratio of six Mcf of natural gas to one Bbl of crude oil, condensate or natural gas liquids.

MMcfe/d. Mmcfe per day.

Net acres or net wells. The sum of the fractional working interest owned in gross acres or gross wells, as the case may be.

Plugging and abandonment. Refers to the sealing off of fluids in the strata penetrated by a well so that the fluids from one stratum will not escape into another or to the surface. Regulations of all states require plugging of abandoned wells.

Productive well. A well that is found to be capable of producing hydrocarbons in sufficient quantities such that proceeds from the sale of the production exceed production expenses and taxes.

Prospect. A specific geographic area which, based on supporting geological, geophysical or other data and also preliminary economic analysis using reasonably anticipated prices and costs, is deemed to have potential for the discovery of commercial hydrocarbons.

Proved developed reserves. Has the meaning given to such term in Rule 4-10(a)(3) of Regulation S-X, which defines proved developed reserves as 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 reserves only after testing by a pilot project or after the operation of an installed program has confirmed through production response that increased recovery will be achieved.

Proved reserves. Has the meaning given to such term in Rule 4-10(a)(2) of Regulation S-X, which defines proved reserves as the estimated quantities of crude oil, natural gas, and natural gas liquids which geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under existing economic and operating conditions, i.e., prices and costs as of the date the estimate is made. Prices include consideration of changes in existing prices provided only by contractual arrangements, but not on escalations based upon future conditions.

Reservoirs are considered proved if economic producibility is supported by either actual production or conclusive formation test. The area of a reservoir considered proved includes (A) that portion delineated by drilling and defined by gas-oil and/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.

Estimates of proved reserves do not include the following: (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 shales, coal, gilsonite and other such sources.

Proved undeveloped reserves. Has the meaning given to such term in Rule 4-10(a)(4) of Regulation S-X, which defines proved undeveloped reserves as 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 undrilled units 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 proved effective by actual tests in the area and in the same reservoir.

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

Trucking. The provision of trucks to move our drilling rigs from one well location to another and to deliver water and equipment to the field.

Undeveloped acreage. Lease acreage on which wells have not been drilled or completed to a point that would permit the production of commercial quantities of natural gas and oil regardless of whether such acreage contains proved reserves.

Working interest. The operating interest that gives the owner the right to drill, produce and conduct operating activities on the property and receive a share of production and requires the owner to pay a share of the costs of drilling and production operations.

PART IV

ITEM 15. Exhibits and Financial Statement Schedules.

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, 2010 and 2009
Consolidated Statements of Operations for the years ended December 31, 2010, 2009 and 2008
Consolidated Statements of Stockholders' Equity for the years ended December 31, 2010, 2009 and 2008
Consolidated Statements of Cash Flows for the years ended December 31, 2010, 2009 and 2008
Notes to Consolidated Financial Statements

(2) Financial Statement Schedule:

Schedule II - Valuation and Qualifying Accounts

(3) Exhibits:

Number	Description
2.1	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 to the Company's Current Report on Form 8-K filed May 15, 2007)
2.2	Purchase and Sale Agreement, dated April 28, 2008, by and among Smith Production, Inc. and Crimson Exploration Inc. (incorporated by reference to Exhibit 2.3 to the Company's Quarterly Report on Form 10-Q for the quarter ended March 31, 2008)
3.1	Certificate of Incorporation of the Registrant (incorporated by reference to Exhibit 3.2 to the Company's Current Report on Form 8-K filed July 5, 2005)
3.2	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)
3.3	Certificate of Designation, Preferences and Rights of Series I Convertible Preferred Stock (incorporated by reference to Exhibit 3.1 to the Company's Current Report on Form 8-K filed October 29, 2010)
3.4	Bylaws of Crimson Exploration Inc. (incorporated by reference to Exhibit 3.7 to the Company's Current Report on Form 8-K filed July 5, 2005)
4.1	Form of Common Stock Certificate (incorporated by reference to Exhibit 3.7 to the Company's Current Report on Form 8-K filed July 5, 2005)
4.2	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 to the Company's Current Report on Form 8-K filed on May 10, 2004)

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

Number	Description
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)
4.5	Waiver, Consent and First Amendment to the Shareholders Rights Agreement, dated as of December 7, 2009, between Crimson Exploration Inc. and OCM GW Holdings, LLC (incorporated by reference to Exhibit 10.3 to the Company's Current Report on Form 8-K filed December 10, 2009)
4.6	Termination Agreement, dated as of December 7, 2009, between Crimson Exploration Inc. and OCM GW Holdings, LLC (incorporated by reference to Exhibit 10.4 to the Company's Current Report on Form 8-K filed December 10, 2009)
#10.1	Amended and Restated Employment Agreement between Allan D. Keel and Crimson Exploration Inc., dated December 30, 2008 (incorporated by reference to Exhibit 10.1 to the Company's Annual Report on Form 10-K for the fiscal year ended December 31, 2008)
#10.2	Amended and Restated Employment Agreement between E. Joseph Grady and Crimson Exploration Inc., dated December 31, 2008 (incorporated by reference to Exhibit 10.2 to the Company's Annual Report on Form 10-K for the fiscal year ended December 31, 2008)
#10.3	GulfWest Energy Inc. 2004 Stock Option Incentive Plan. (incorporated by reference to Exhibit 10.4 to the Company's Annual Report on Form 10-K for the fiscal year ended December 31, 2004)
#10.4	GulfWest Energy Inc. 2005 Stock Option Incentive Plan (incorporated by reference to Exhibit 10.5 to the Company's Annual Report on Form 10-K for the fiscal year ended December 31, 2004)
#10.5	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 fiscal year ended December 31, 2005)
#10.6	Form of Indemnification Agreement for directors and officers (incorporated by reference to Exhibit 10.3 to the Company's Current Report on Form 8-K filed on July 21, 2005)
10.7	Subscription Agreement between Crimson Exploration Inc. and America Capital Energy Corporation dated September 24, 2010 (incorporated by reference to Exhibit 10.1 of the Company's Current Report on Form 8-K filed on October 29, 2010)
10.8	Option Agreement between Crimson Exploration Inc. and America Capital Energy Corporation dated October 26, 2010 (incorporated by reference to Exhibit 10.2 of the Company's Current Report on Form 8-K filed on October 29, 2010)
10.9	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 to the Company's Registration Statement No. 333-116048 on Form S-1)

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

Number	Description
#10.10	Amended and Restated Employment Agreement between Tracy Price and Crimson Exploration Inc., dated December 30, 2008 (incorporated by reference to Exhibit 10.11 to the Company's Annual Report on Form 10-K for the fiscal year ended December 31, 2010)
#10.11	Amended and Restated Employment Agreement between Tommy Atkins and Crimson Exploration Inc., dated December 29, 2008 (incorporated by reference to Exhibit 10.12 to the Company's Annual Report on Form 10-K for the fiscal year ended December 31, 2008)
#10.12	Amended and Restated Employment Agreement between Jay S. Mengle and Crimson Exploration Inc., dated December 31, 2008 (incorporated by reference to Exhibit 10.13 to the Company's Annual Report on Form 10-K for the fiscal year ended December 31, 2008)
#10.13	Summary terms of Director Compensation Plan (incorporated by reference to Exhibit 10.14 to the Company's Annual Report on Form 10-K for the fiscal year ended December 31, 2008)
#10.14	Form of director and officer restricted stock grant (incorporated by reference to Exhibit 10.2 to the Company's Current Report on Form 8-K filed on July 21, 2005)
#10.15	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)
10.16	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)
#10.17	Crimson Exploration Inc. 2005 Stock Incentive Plan, Amended and Restated Effective as of August 15, 2008 (incorporated by reference to Exhibit A of the Company's Information Statement on Schedule 14C filed September 25, 2008)
#10.18	Form of Restricted Stock Award used in connection with option exchange and in connection with the Long-Term Incentive Plan (incorporated by reference to Exhibit 99.1 to the Company's Current Report on Form 8-K filed September 11, 2008)
#10.19	Long-Term Incentive Plan (incorporated by reference to Exhibit 10.3 to the Company's Quarterly Report on Form 10-Q for the quarter ended September 30, 2008)
#10.20	Cash Incentive Bonus Plan (incorporated by reference to Exhibit 10.4 to the Company's Quarterly Report on Form 10-Q for the quarter ended September 30, 2008)
#10.21	Long Term Performance Plan Form of Restricted Stock Award Agreement for Employees (incorporated by reference to Exhibit 10.1 to the Company's Quarterly Report on Form 10-Q for the quarter ended March 31, 2009)

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

Number	Description
#10.22	Long Term Incentive Performance Plan Form of Stock Option Agreement for Employees (incorporated by reference to Exhibit 10.2 to the Company's Quarterly Report on Form 10-Q for the quarter ended March 31, 2009)
#10.23	Long Term Incentive Performance Plan Form of Restricted Stock Award Agreement for Executive Officers (incorporated by reference to Exhibit 10.3 to the Company's Quarterly Report on Form 10-Q for the quarter ended March 31, 2009)
#10.24	Long Term Incentive Performance Plan Form of Restricted Stock Option Agreement for Executive Officers (incorporated by reference to Exhibit 10.4 to the Company's Quarterly Report on Form 10-Q for the quarter ended March 31, 2009)
10.25	First Amendment, dated as of July 31, 2009, to the Amended and Restated Credit Agreement, dated as of May 31, 2007, by and among Crimson Exploration Inc., the guarantor party thereto, the lender parties thereto and Wells Fargo Bank, National Association (incorporated by reference to Exhibit 10.1 to the Company's Current Report on Form 8-K filed August 5, 2009)
10.26	Second Amendment, dated as of November 6, 2009, to the Amended and Restated Credit Agreement, dated as of May 31, 2007, among Crimson Exploration Inc., the guarantor party thereto, the lender parties thereto and Wells Fargo Bank, National Association (incorporated by reference to Exhibit 10.1 to the Company's Current Report on Form 8-K filed November 13, 2009)
10.27	Third Amendment and Limited Waiver, dated as of November 6, 2009, to the Amended and Restated Credit Agreement, dated as of May 31, 2007, among Crimson Exploration Inc., the guarantor party thereto, the lender parties thereto and Wells Fargo Bank, National Association (incorporated by reference to Exhibit 10.2 to the Company's Current Report on Form 8-K filed November 13, 2009)
10.28	Promissory Note, dated November 6, 2009, made by Crimson Exploration Inc. to Wells Fargo Bank, National Association (incorporated by reference to Exhibit 10.4 to the Company's Current Report on Form 8-K filed November 13, 2009)
10.29	Fourth Amendment, dated as of December 7, 2009, to the Amended and Restated Credit Agreement, dated as of May 31, 2007, among Crimson Exploration Inc., the guarantor party thereto, the lender parties thereto and Wells Fargo Bank, National Association (incorporated by reference to Exhibit 10.1 to the Company's Current Report on Form 8-K filed December 10, 2009)
10.30	Fifth Amendment dated as of June 9, 2010, to the Amended and Restated Credit Agreement, dated as of May 31, 2007, by and among Crimson Exploration Inc., as borrower, the Guarantors party thereto, the Lenders from time to time party thereto and Wells Fargo Bank, National Association, as administrative agent for the Lenders (incorporated by reference to Exhibit 10.1 to the Company's Amendment No. 1 to Quarterly Report on Form 10-Q for the quarterly period ended June 30, 2010
# 10.31	Employment Agreement between Carl Isaac and Crimson Exploration Inc., dated May 10, 2010 (incorporated by reference to Exhibit 10.2 to the Company's Quarterly Report on Form 10-Q for the quarter ended June 30, 2010)
10.32	Registration Rights Agreement between Crimson Exploration Inc. and America Capital Energy corporation, dated as of December 22, 2010 (incorporated by reference to Exhibit 10.1 to the Company's Current Report on Form 8-K filed December 28, 2010)

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

Number	Description
10.33	Second Lien Credit Agreement, dated as of December 27, 2010, among Crimson Exploration Inc., as borrower, Barclays Bank PLC, as agent, and each lender from time to time party thereto (incorporated by reference to Exhibit 10.2 to the Company's Current Report on Form 8-K filed December 28, 2010)
10.35	Sixth Amendment, dated as of December 27, 2010, to the Amended and Restated Credit Agreement, dated as of May 31, 2007, among Crimson Exploration Inc., the guarantor party thereto, the lender parties thereto and Wells Fargo Bank, National Association (incorporated by reference to Exhibit 10.3 to the Company's Current Report on Form 8-K filed December 28, 2010)
10.41	Intercreditor Agreement, dated as of December 27, 2010, among Crimson Exploration Inc., as borrower, Wells Fargo Bank, National Association, as First Lien Agent, and Barclays Bank PLC, as Second Lien Agent (incorporated by reference to Exhibit 10.4 to the Company's Current Report on Form 8-K filed December 28, 2010)
*21.1	Significant Subsidiaries of the Registrant
*23.1	Consent of Grant Thornton LLP
*23.2	Consent of Netherland, Sewell & Associates, Inc.
25.1	Power of Attorney (included on signature page of this Annual Report)
*31.1	Certification of Chief Executive Officer pursuant to Exchange Rule 13a-15(e) as adopted pursuant to Section 302 of the Sarbanes-Oxley Act of 2002
*31.2	Certification of Chief Financial Officer pursuant to Exchange Rule 13a-15(e) as adopted pursuant to Section 302 of the Sarbanes-Oxley Act of 2002
*32.1	Certification of Chief Executive Officer pursuant to 18.U.S.C Section 1350 pursuant to Section 906 of the Sarbanes-Oxley Act of 2002
*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
*99.1	Estimate of Reserves and Future Revenue to the Crimson Exploration Inc. Interest in Certain Oil and Gas Properties located in the United States and in the Gulf of Mexico as of December 31, 2010 provided by Netherland, Sewell and Associates, Inc.

* filed herewith
# management contract or compensatory plan or arrangement

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized.

CRIMSON EXPLORATION INC.

Date: March 18, 2011

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 capacities and on the dates indicated.

Signature	Title	Date
/s/ Allan D. Keel Allan D. Keel	President, Chief Executive Officer and Director	March 18, 2011
/s/ E. Joseph Grady E. Joseph Grady	Senior Vice President and Chief Financial Officer	March 18, 2011
/s/ B. James Ford B. James Ford	Director	March 18, 2011
/s/ Lon McCain Lon McCain	Director	March 18, 2011
/s/ Lee B. Backsen Lee B. Backsen	Director	March 18, 2011
/s/ Adam C. Pierce Adam C. Pierce	Director	March 18, 2011
/s/ Cassidy J. Traub Cassidy J. Traub	Director	March 18, 2011
/s/ Ni Zhaoxing Ni Zhaoxing	Director	March 18, 2011

CRIMSON EXPLORATION INC.

FINANCIAL REPORT

DECEMBER 31, 2010

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. 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, 2010. 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, 2010.

/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

Houston, Texas
MARCH 18, 2011

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

Board of Directors and Stockholders

Crimson Exploration Inc.

We have audited the accompanying consolidated balance sheets of Crimson Exploration Inc. and subsidiaries (collectively, the "Company") as of December 31, 2010 and 2009, and the related consolidated statements of operations, stockholders' equity, and cash flows for each of the three years in the period ended December 31, 2010. 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, 2010 and 2009, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2010, in conformity with accounting principles generally accepted in the United States of America.

/s/ GRANT THORNTON LLP

Houston, Texas

March 18, 2011

PART I. FINANCIAL INFORMATION

ITEM 1. FINANCIAL STATEMENTS.

CRIMSON EXPLORATION INC. AND SUBSIDIARIES
CONSOLIDATED BALANCE SHEETS
ASSETS

	December 31, 2010	December 31, 2009
CURRENT ASSETS		
Cash and cash equivalents	$ —	$ —
Accounts receivable, net of allowance (see Note 2)	14,225,932	14,773,246
Prepaid expenses	168,766	—
Derivative instruments	6,836,366	9,937,697
Deferred tax asset, net	6,331,152	—
Total current assets	27,562,216	24,710,943
PROPERTY AND EQUIPMENT		
Oil and gas properties (successful efforts method of accounting)	590,248,138	559,565,531
Other property and equipment	3,345,798	3,679,515
Accumulated depreciation, depletion and amortization	(213,547,504)	(170,117,319)
Total property and equipment, net	380,046,432	393,127,727
NONCURRENT ASSETS		
Deposits	34,743	104,697
Debt issuance cost	2,364,469	4,347,298
Derivative instruments	—	2,513,369
Deferred tax asset, net	2,678,966	—
Total noncurrent assets	5,078,178	6,965,364
TOTAL ASSETS	$ 412,686,826	$ 424,804,034

LIABILITIES AND STOCKHOLDERS' EQUITY

	December 31, 2010	December 31, 2009
CURRENT LIABILITIES		
Current portion of long-term debt	$ —	$ 19,014
Accounts payable	30,795,692	20,263,343
Income tax payable	—	250,931
Accrued liabilities	12,799,176	8,852,310
Asset retirement obligations	732,126	330,287
Derivative instruments	3,043,078	872,849
Deferred tax liability, net	—	2,897,300
Total current liabilities	47,370,072	33,486,034
NONCURRENT LIABILITIES		
Long-term debt, net of current portion	172,013,490	192,749,751
Asset retirement obligations	9,101,895	9,372,366
Derivative instruments	—	1,284,105
Deferred tax liability, net	—	4,471,023
Other noncurrent liabilities	670,398	709,867
Total noncurrent liabilities	181,785,783	208,587,112
Total liabilities	229,155,855	242,073,146
COMMITMENTS AND CONTINGENCIES (see Note 10)		
STOCKHOLDERS' EQUITY		
Common stock (Par value $0.001; 200,000,000 shares authorized; 44,952,405 and 38,578,204 shares issued and 44,857,259 and 38,516,658 shares outstanding as of December 31, 2010 and 2009, respectively)	44,952	38,578
Additional paid-in capital	241,488,749	209,738,513
Retained deficit	(57,506,788)	(26,661,891)
Treasury stock (At cost, 95,146 and 61,546 shares as of December 31, 2010 and 2009, respectively)	(495,942)	(384,312)
Total stockholders' equity	183,530,971	182,730,888
TOTAL LIABILITIES AND STOCKHOLDERS' EQUITY	$ 412,686,826	$ 424,804,034

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,		
	2010	2009	2008
OPERATING REVENUES			
Natural gas sales	$ 59,861,551	$ 71,494,889	$ 116,414,956
Crude oil sales	22,021,906	27,283,772	41,860,385
Natural gas liquids sales	14,048,766	13,024,103	27,404,774
Operating overhead and other income	609,744	644,882	1,088,158
Total operating revenues	96,541,967	112,447,646	186,768,273
OPERATING EXPENSES			
Lease operating expenses	15,001,954	17,358,670	20,824,629
Production and ad valorem taxes	6,061,033	7,131,400	16,266,493
Exploration expenses	967,322	2,723,953	2,609,593
Depreciation, depletion and amortization	45,022,272	53,294,809	50,466,966
Impairment and abandonment of oil and gas properties	22,254,059	6,721,215	43,309,365
General and administrative	20,480,608	18,757,981	22,405,639
Loss (gain) on sale of assets	1,069,616	6,847,454	(15,209,706)
Total operating expenses	110,856,864	112,835,482	140,672,979
INCOME (LOSS) FROM OPERATIONS	(14,314,897)	(387,836)	46,095,294
OTHER INCOME (EXPENSE)			
Interest expense, net of amount capitalized	(22,324,535)	(23,172,082)	(21,108,603)
Other financing costs	(4,311,779)	(3,341,854)	(1,501,627)
Unrealized (loss) gain on derivative instruments	(6,500,825)	(23,862,580)	49,408,961
Total other income (expense)	(33,137,139)	(50,376,516)	26,798,731
INCOME (LOSS) BEFORE INCOME TAXES	(47,452,036)	(50,764,352)	72,894,025
Income Tax Benefit (Expense)	16,607,139	16,694,362	(26,690,807)
NET INCOME (LOSS)	(30,844,897)	(34,069,990)	46,203,218
Dividends on Preferred Stock	—	(4,522,645)	(4,234,050)
NET INCOME (LOSS) AVAILABLE TO COMMON STOCKHOLDERS	$ (30,844,897)	$ (38,592,635)	$ 41,969,168
NET INCOME (LOSS) PER SHARE			
Basic	$ (0.78)	$ (4.91)	$ 7.81
Diluted	$ (0.78)	$ (4.91)	$ 4.46
WEIGHTED AVERAGE SHARES OUTSTANDING			
Basic	39,397,486	7,861,054	5,371,377
Diluted	39,397,486	7,861,054	10,360,348

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, 2010, 2009 and 2008

	NUMBER OF SHARES OUTSTANDING							
	PREFERRED STOCK	COMMON STOCK	PREFERRED STOCK	COMMON STOCK	ADDITIONAL PAID-IN CAPITAL	RETAINED EARNINGS (DEFICIT)	TREASURY STOCK	TOTAL STOCKHOLDERS' EQUITY
BALANCE, DECEMBER 31, 2007	83,200	5,127,937	$ 832	$ 5,128	$ 89,507,073	$ (19,859,952)	$ —	$ 69,653,081
Current year net income	—	—	—	—	—	46,203,218	—	46,203,218
Share-based compensation	—	547,168	—	547	5,670,051	—	—	5,670,598
Stock options exercised	—	75,000	—	75	346,425	—	—	346,500
Preferred G converted	(500)	27,778	(5)	28	(23)	—	—	—
Preferred H converted	(100)	14,286	(1)	14	(13)	—	—	—
Dividends paid on preferred stock	—	15,743	—	16	153,362	(153,378)	—	—
Treasury stock	—	(20,625)	—	—	—	—	(250,594)	(250,594)
BALANCE, DECEMBER 31, 2008	82,600	5,787,287	826	5,808	95,676,875	26,189,888	(250,594)	121,622,803
Current year net loss	—		—	—	—	(34,069,990)	—	(34,069,990)
Share-based compensation	—	661,156	—	661	2,400,231	—	—	2,400,892
Preferred G converted	(80,500)	8,050,000	(805)	8,050	(7,245)	—	—	—
Preferred H converted	(2,100)	300,001	(21)	300	(279)	—	—	—
Dividends paid on preferred stock	—	3,759,135	—	3,759	18,778,030	(18,781,789)	—	—
Common stock issuance	—	20,000,000	—	20,000	92,890,901	—	—	92,910,901
Treasury stock	—	(40,921)	—	—	—	—	(133,718)	(133,718)
BALANCE, DECEMBER 31, 2009	—	38,516,658	—	38,578	209,738,513	(26,661,891)	(384,312)	182,730,888
Current year net loss	—	—	—	—	—	(30,844,897)	—	(30,844,897)
Share-based compensation	—	345,820	—	346	1,788,685	—	—	1,789,031
Stock options exercised	—	28,381	—	28	68,086	—	—	68,114
Common stock issuance	—	6,000,000	—	6,000	29,893,465	—	—	29,899,465
Treasury stock	—	(33,600)	—	—	—	—	(111,630)	(111,630)
BALANCE, DECEMBER 31, 2010	—	44,857,259	$ —	$ 44,952	$ 241,488,749	$ (57,506,788)	$ (495,942)	$ 183,530,971

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, 2010	2009	2008
CASH FLOWS FROM OPERATING ACTIVITIES:			
Net income (loss)	$ (30,844,897)	$ (34,069,990)	$ 46,203,218
Adjustments to reconcile net income (loss) to net cash provided by operating activities:			
Depreciation, depletion and amortization	45,022,272	53,294,809	50,466,966
Asset retirement obligations	(162,668)	(375,149)	(546,840)
Stock compensation expense	1,789,031	2,400,892	5,434,992
Amortization of debt issuance cost	3,929,136	3,156,687	1,091,929
Discount on notes payable	263,739	10,794	—
Deferred charges	—	1,324,907	75,093
Deferred income taxes	(16,378,441)	(16,572,200)	25,563,734
Impaired and abandoned oil and gas properties	22,254,059	6,721,215	43,309,365
Loss (gain) on sale of assets	1,069,616	6,847,454	(15,209,706)
Unrealized loss (gain) on derivative instruments	6,500,825	23,862,580	(49,408,961)
Provision for bad debts	167,819	239,676	—
Changes in operating assets and liabilities:			
Decrease in accounts receivable – trade, net	379,494	6,065,890	8,973,958
Decrease (increase) in prepaid expenses	(168,766)	77,293	153,577
(Decrease) increase in accounts payable and accrued liabilities	14,188,815	(43,329,185)	27,661,406
Net cash provided by operating activities	48,010,034	9,655,673	143,768,731
CASH FLOWS FROM INVESTING ACTIVITIES:			
Sale of assets	(224,776)	7,553,480	34,923,332
Acquisition of oil and gas properties	—	493,532	(58,481,721)
Capital expenditures	(54,745,840)	(21,893,154)	(141,794,612)
Deposits	69,954	—	(10,106)
Net cash used in investing activities	(54,900,662)	(13,846,142)	(165,363,107)
CASH FLOWS FROM FINANCING ACTIVITIES:			
Proceeds from issuance of common stock	29,967,579	92,910,901	346,500
Purchase of treasury stock	(111,630)	(133,718)	(250,594)
Payments on debt	(286,802,034)	(196,079,649)	(132,393,063)
Proceeds from debt	265,783,020	110,367,869	149,009,022
Debt issuance expenditures	(1,946,307)	(2,874,934)	—
Net cash provided by financing activities	6,890,628	4,190,469	16,711,865
INCREASE (DECREASE) IN CASH AND CASH EQUIVALENTS	—	—	(4,882,511)
CASH AND CASH EQUIVALENTS, Beginning of year	—	—	4,882,511
CASH AND CASH EQUIVALENTS, End of year	$ —	$ —	$ —
Cash paid for interest, net of capitalized interest	$ 25,982,510	$ 20,092,443	$ 22,484,711
Cash paid for income taxes	$ 22,233	$ 173,851	$ 580,129

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

1. Organization

Crimson Exploration Inc., together with its subsidiaries, (*"Crimson"*, *"we"*, *"our"*, *"us"*) is an independent energy company engaged in the acquisition, exploitation, exploration and development of natural gas and crude oil properties. We have historically focused our operations in the onshore U.S. Gulf Coast and South Texas regions, which are generally characterized by high rates of return in known, prolific producing trends. We have recently expanded our strategic focus to include longer reserve life resource plays that we believe provide significant long-term growth potential in multiple formations.

We intend to grow reserves and production by developing our existing producing property base, developing our East Texas and South Texas resource potential, and pursuing opportunistic acquisitions in areas where we have specific operating expertise. We have developed a significant project inventory of associated with our existing property base. Our technical team has a successful track record of adding reserves through the drillbit. Since January 2008, we have drilled 42 gross (19.0 net) wells with an overall success rate of 93%. At December 31, 2010, we had two wells in progress.

As of December 31, 2010, our proved reserves, as estimated by our independent reserve engineering firm, Netherland, Sewell & Associates, Inc., in accordance with reserve reporting guidelines mandated by the SEC, were 166.5 Bcfe, consisting of 135.7 Bcf of natural gas and 5.1 MMBbl of crude oil, condensate and natural gas liquids, with a PV-10 of $239.7 million. As of December 31, 2010, 81% of our proved reserves were natural gas, 48% were proved developed and 89% were attributed to wells and properties operated by us. During 2010 we grew proved reserves from 97.5 Bcfe at December 31, 2009 to 166.5 Bcfe at December 31, 2010. Our average daily production decreased from 40.9 MMcfe/d for the twelve months ended December 31, 2009 to 35.4 MMcfe/d for the twelve months ended December 31, 2010.

2. Summary of Significant Accounting Policies

Basis of Presentation

Our consolidated financial statements have been prepared in accordance with accounting principles generally accepted in the United States. Our operations are considered to fall within a single industry segment, which is the acquisition, development, exploitation and production of natural gas and crude oil properties in the United States. All significant intercompany balances and transactions have been eliminated upon consolidation. Certain reclassifications have been made to the prior year financial statements to conform to the current year presentation. Significant policies are discussed below.

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.

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. Significant estimates included in the consolidated financial statements are: (1) natural gas, crude oil and natural gas liquids revenues and reserves; (2) depreciation, depletion and amortization; (3) valuation allowances associated with income taxes and accounts receivables; (4) accrued assets and liabilities; (5) stock-based compensation; (6) asset retirement obligations;

(7) valuation of derivative instruments and (8) impairment of oil and gas properties. Although management believes these estimates are reasonable, changes in facts and circumstances or discovery of new information may result in revised estimates. Actual results could differ from those estimates.

Oil and Gas Properties

We use the successful efforts method of accounting for natural gas and crude oil producing activities. Costs to acquire mineral interests in natural gas and crude oil properties are capitalized. Costs to drill and develop development wells and costs to drill and develop exploratory wells that find proved reserves are also 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).

Capitalized costs of producing natural gas and crude oil properties and support equipment, net of estimated salvage values, are depleted by the unit-of-production method.

Oil and Gas Reserves

The estimates of proved natural gas, crude oil and natural gas liquids reserves utilized in the preparation of the financial statements are estimated in accordance with guidelines established by the Securities and Exchange Commission (*"SEC"*) and the Financial Accounting Standards Board (*"FASB"*), which require that reserve estimates be prepared under existing economic and operating conditions using a 12-month average price with no provision for price and cost escalations in future years 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 deplete capitalized natural gas, crude oil and natural gas liquids costs on the unit of production method, based upon these reserve estimates. It is possible that, because of changes in market conditions or the inherent imprecise nature of these reserve estimates, that the estimates of future cash inflows, future gross revenues, the amount of natural gas, crude oil and natural gas liquids reserves, the remaining estimated lives of the natural gas and crude oil properties, or any combination of the above may be increased or reduced. See Note 17 – "Oil and Gas Reserves (unaudited)" for further information.

Capitalized Interest

Interest is capitalized as part of the historical cost of acquiring assets. Natural gas and crude oil investments in exploration and development drilling activities that are in progress qualify for interest capitalization. Capitalized interest is calculated by multiplying the weighted-average interest rate on debt used to finance the asset by the amount of qualifying costs. Capitalized interest cannot exceed gross interest expense. Any associated capitalized interest is transferred to the appropriate asset and is depleted by the unit of production method. Capitalized interest was approximately $0.1 million, $25,000 and $0.9 million in 2010, 2009 and 2008 respectively.

Asset Retirement Obligations

We recognize an estimated liability for the plugging and abandonment of our natural gas and crude oil 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 the related assets are placed in service or acquired. The liability is accreted to its present value each period and the capitalized cost is depleted over the useful life of the related asset. The accretion expense is included in depreciation, depletion and amortization (*"DD&A"*) expense.

The estimated liability is based on historical experience in plugging and abandoning wells. The estimated remaining lives of the wells is based on reserve life 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 changes in the 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. This gain or loss on abandonment is included in impairment and abandonment of oil and gas properties expense.

Impairment of Oil and Gas Properties

Impairments, measured using fair market value, are recognized whenever events or changes in circumstances indicate that the carrying amount of long-lived assets may not be recoverable and the future undiscounted cash flows attributable to the asset are less than its carrying value. See Note 3 — "Oil and Gas Properties" for further information.

Unproved Leasehold Costs

The costs of unproved leaseholds, including associated interest costs for the period activities that were in progress to bring projects to their intended use, are capitalized pending the results of exploration efforts. We regularly assess on a property-by-property basis the impairment of individual unproved properties whose acquisition costs are relatively significant. Unproved properties whose acquisition costs are not relatively significant are amortized in the aggregate over the lesser of three years or the average remaining lease term. As exploration work progresses and the reserves on significant properties are proven, capitalized costs of these properties will be subject to depreciation and depletion. If the exploration work is unsuccessful, the capitalized costs of the properties related to the unsuccessful work will be charged to exploration expense. The timing of any write-downs of these unproven properties, if warranted, depends upon the nature, timing and extent of future exploration and development activities and their results.

Revenue Recognition and Oil and Gas Imbalances

We follow the “sales” method of accounting for natural gas, crude oil and natural gas liquids 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 natural gas and crude oil marketing companies for the sale of natural gas, crude oil and natural gas liquids. In addition, we grant credit to our oil and gas working interest partners. Receivables from our working interest partners are generally secured by the underlying ownership interests in the properties.

The accounts receivable (“*A/R*”) balance at year-end primarily relates to A/R Trade (net of allowance for doubtful accounts), A/R joint interest billing (net of legal suspense/prepayments from partners), Accrued revenue (two months for operated properties, three months for non-operated properties), and A/R Other. Accrued revenue is recorded net to our interest (excludes outside interest holders).

The allowance for doubtful accounts is recognized by management based upon a review of specific customer balances, historical losses and general economic conditions. The allowance for doubtful accounts at December 31, 2010 and 2009 was $579,143 and $411,324, respectively.

Fair Value Measurements

Accounting guidance establishes a single authoritative definition of fair value based upon the assumptions market participants would use when pricing an asset or liability and creates a fair value hierarchy that prioritizes the information used to develop those assumptions. Additional disclosures are required, including disclosures of fair value measurements by level within the fair value hierarchy. We incorporate a credit risk assumption into the measurement of certain assets and liabilities. See Note 5 – “Fair Value Measurements” for further information.

Debt Issuance Costs

Debt issuance costs incurred are capitalized and subsequently amortized over the term of the related debt.

Earnings (Loss) Per Share

Basic earnings (loss) per share are based on the weighted-average number of outstanding common shares. Diluted earnings (loss) per-share are based on the weighted-average number of outstanding common shares and the effect of all potentially diluted common shares. See Note 13 – "Income (Loss) Per Common Share" for further information.

Share-Based Compensation

We measure the grant date fair value of stock options and other stock-based compensation issued to employees and directors and expense the fair value over the requisite service period of the award. 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.

We estimate forfeitures based on historical data 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, employees and directors. See Note 12 – "Share-Based Compensation" for further information.

Income Taxes

Income taxes are accounted for under the asset and liability method. Deferred tax assets and liabilities are recognized when items of income and expense are recognized in the financial statements in different periods than when recognized in the applicable tax return. Deferred tax assets arise when expenses are recognized in the financial statements before the tax returns or when income items are recognized in the tax return prior to the financial statements. Deferred tax assets also arise when operating losses or tax credits are available to offset tax payments due in future years. Deferred tax liabilities arise when income items are recognized in the financial statements before the tax returns or when expenses are recognized in the tax return prior to the financial statements. Deferred tax assets and liabilities are measured using enacted tax rates expected to apply to taxable income in the years in which those temporary differences are expected to be recovered or settled. The effect on deferred tax assets and liabilities of a change in tax rates is recognized in income in the period that includes the date when the change in the tax rate was enacted.

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. In addition we routinely assess uncertain tax positions, and accrue for tax positions that are not more-likely-than-not to be sustained upon examination by taxing authorities. See Note 15 — "Income Taxes" for further information.

New Accounting Standards Adopted in 2010

In April 2010, the Financial Accounting Standards Board ("*FASB*") issued Accounting Standards Update ("*ASU*") No. 2010-14, *Accounting for Extractive Industries—Oil and Gas (Topic 932): Amendments to Paragraph 932-10-S99-1 ("ASU 2010-14").* ASU 2010-14 incorporates updated text changes to Rule 4-10 of the Securities and Exchange Commission ("*SEC*") Regulation S-X into the FASB's Accounting Standards Codification ("*ASC*"). The amendments reflect changes to fossil fuel exploration and production definitions, and addresses issues associated with new technology implemented over the past several decades. Specifically, the additional text added to FASB ASC 932-10-S99-1 reflects changes previously included in SEC Final Rulemaking Release No. 33-8995, *Modernization of Oil and Gas Reporting*, which became effective on January 1, 2010. The adoption of this ASU did not have a material impact on our financial position, results of operations or cash flows.

In February 2010, the FASB issued ASU No. 2010-09, *Subsequent Events (Topic 855): Amendments to Certain Recognition and Disclosure Requirements ("ASU 2010-09").* ASU 2010-09 amends Subtopic 855-10 to remove some contradictions between the requirements of U.S. GAAP and the SEC's filing rules. As a result, public companies will no longer have to disclose the date through which subsequent events have been evaluated. We adopted these amendments as of February 24, 2010, with the issuance of this ASU. The adoption of this ASU did not have a material impact on our financial position, results of operations or cash flows.

We adopted FASB ASU No. 2010-06, *Fair Value Measurements and Disclosures (Topic 820): Improving Disclosures about Fair Value Measurements* ("*ASU 2010-06*") on January 1, 2010. ASU 2010-06 requires, among other items, reporting entities to provide information about movements of assets among Levels 1 and 2 of the three-tier fair value hierarchy established by FASB ASC 820. The adoption of this ASU did not have a material impact on our financial position, results of operations or cash flows.

3. Oil and Gas Properties

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:

	2010	2009
Unproved oil and gas properties	$ 31,885,067	$ 68,614,143
Proved oil and gas properties	519,765,781	461,679,614
Wells and related equipment and facilities	38,597,290	29,271,774
	590,248,138	559,565,531
Less accumulated depreciation, depletion and amortization	(211,506,271)	(168,431,710)
Net capitalized costs	$ 378,741,867	$ 391,133,821

The following table sets forth the composition of exploration expenses:

	2010	2009	2008
Lease rental expense	$ 70,839	$ 224,258	$ 172,384
Geological and geophysical	591,909	1,733,426	1,692,102
Settled asset retirement obligations	304,574	766,269	745,107
	$ 967,322	$ 2,723,953	$ 2,609,593

The following table sets forth the composition of impairment and abandonment expenses:

	2010	2009	2008
Impairment of proved properties	$ 473,105	$ 3,183,256	$ 35,953,586 (2)
Impairment of unproved properties	20,578,921 (1)	—	—
Abandonment of proved properties	—	2,475,642	—
Abandonment of unproved properties	1,202,033	1,062,317	7,355,779 (3)
	$ 22,254,059	$ 6,721,215	$ 43,309,365

(1) Primarily related to acreage in East Texas

(2) $25.8 million was related to our Madisonville Field in Southeast Texas and $10.2 million was primarily related to our Grand Lake Field in Southwest Louisiana which was sold in December 2009

(3) Primarily related to the release of our undeveloped leasehold position that we acquired from Core Natural Resources in Culberson County, Texas in 2006

Costs Incurred in Oil and Gas Producing Activities:

	2010	2009	2008
Property Acquisitions			
Proved	$ —	$ (493,532)	$ 60,765,315
Unproved	5,774,043	1,833,949	57,203,337
Development Costs	47,973,323	11,398,237	86,685,192
Exploration Costs	2,000,941	11,815,450	2,520,389
	$ 55,748,307	$ 24,554,104	$ 207,174,233

These costs include oil and gas property acquisition, exploration and development activities regardless of whether the costs were capitalized or charged to expense, including lease rental expenses, geological and geophysical expenses and changes to the long-lived asset related to our asset retirement obligation.

The following table shows oil and gas property dispositions:

	2010	2009	2008
Oil and gas properties	$ 2,601,997	$ 42,995,459	$ 21,765,688
Accumulated depreciation, depletion and amortization	(1,406,066)	(23,158,221)	(1,659,588)
Net oil and gas properties	$ 1,195,931	$ 19,837,238	$ 20,106,100

The dispositions resulted in a net loss of $1.1 million, $6.8 million and a net gain of $15.2 million for 2010, 2009 and 2008, respectively.

4. Acquisitions and Dispositions of Oil and Gas Properties

Southwest Louisiana Disposition

On December 28, 2009, we closed on a definitive agreement to sell operated and non-operated working interests in various producing wells, related production equipment and associated acreage primarily in Cameron, Calcasieu and Jefferson Davis parishes in Southwest Louisiana, with an effective date of October 1, 2009. The final total consideration paid by the buyer of $7.8 million was based on existing wells and undeveloped acreage owned by us at the time of the closing. The assets include substantially all of our Southwest Louisiana properties, representing approximately 7.6 Bcfe of proved reserves as of September 30, 2009, with average daily production of approximately 3.1 Mmcfe/d for the year ended December 31, 2009. The net proceeds of $7.3 million were primarily used to repay amounts outstanding under our senior revolving credit agreement. Our net book value of these assets sold was $18.8 million and the liabilities assumed by the buyer on these assets were $5.3 million, which resulted in a loss of $6.2 million. The sale of these assets represented a strategic exit from operations in Southwest Louisiana.

East Texas Acreage Acquisition

Since the second half of 2008, we obtained natural gas and crude oil leases from mineral interest owners covering approximately 18,200 gross (12,700 net) acres acquired in 2008 and 2009 in the highly prospective gas resource play in San Augustine and Sabine Counties, where we are focusing primarily on the pursuit of the Haynesville Shale, Mid-Bossier Shale and James Lime formations. In November 2009, we announced the completion and initial production of our first well on this acreage, the Kardell #1H, with the horizontal completion in the Haynesville Shale formation. In 2010, we began the operated phase of our drilling program in East Texas with our Grizzly #1 well which we completed in the Mid-Bossier formation and which began commercial production in August 2010. We then completed our Gobi #1H well in the Mid-Bossier and it commenced production November 2010. All three of these wells are in our Bruin Prospect Area in San Augustine County. At the end of February 2011 we completed the Bengal #1H, which is the first well in our Tiger Prospect Area in Sabine County, Texas and it is currently being put on production. We also participated on a non-operated basis, in the drilling of the first well in our Fairway Farms Prospect Area, the Halbert Trust GU #1, a Mid-Bossier completion that commenced production in December 2010.

Smith Acquisition

In May 2008, we acquired four producing gas fields and undeveloped acreage in South Texas from Smith Production Inc. (*"Smith"*) for a purchase price of $65.0 million with an economic effective date of January 1, 2008. After adjustment for the estimated results of operations, and other typical purchase price adjustments of approximately $7.4 million for the period between the effective date and the closing date, the cash consideration was approximately $57.6 million. The assets acquired consist of a 25% non-operated working interest in the Samano Field located in Starr and Hidalgo Counties, a 100% operated working interest in the North Bob West Field in Zapata County and 100% operated working interests in the Brushy Creek and Hope Fields in DeWitt County. We acquired an interest in over 16,000 gross acres with these fields, most of which is held by production. Production from the acquired assets was averaging approximately 7 MMcfe/d at closing.

The adjusted price for this acreage, with adjustment of the reserves for approximately one Bcfe of production for the interim operations between the effective date and closing, represents a purchase cost of $2.82 per Mcfe for approximately 21 Bcfe of proved reserves and $8,300 per Mcfe of current average daily production. We financed this acquisition with cash flows from operations, proceeds from the sale of assets and from borrowings available under our revolving credit agreement. For the year ended December 31, 2008, seven months of revenues and expenses, $11.7 million and $3.7 million, respectively, were included in our financial results of operations.

Barnett Shale Disposition

In January 2008, we and our operator-partner 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-operated working interest in the assets being sold and had 1.5 Bcfe in proved reserves at December 31, 2007. The total consideration paid by the buyer was based on existing wells and undeveloped acreage owned by us and our partner at the time of the final closing. Our share of the consideration received was approximately $34.4 million. Proceeds received for our interest were primarily used to repay amounts outstanding under our revolving credit agreement and to help finance our acquisition of the properties from Smith. Our net book value of the assets sold was $18.8 million, which resulted in a gain of $15.6 million.

5. Fair Value Measurements

Certain of our assets and liabilities are reported at fair value in our consolidated balance sheets. The following methods and assumptions were used to estimate the fair values for each class of financial instruments:

Cash and Cash Equivalents, Accounts Receivable and Accounts Payable. The carrying amounts approximate fair value due to the short-term nature or maturity of the instruments.

Derivative Instruments. Our derivative instruments consist of variable to fixed price commodity swaps, costless collars and interest rate swaps. The fair value measurement of our unrealized natural gas, crude oil and interest rate swaps and collars were obtained from financial institutions and were evaluated for accuracy using our crude oil, natural gas and interest rate swap and collar agreements and future commodity and interest rate curves. Differences between management's calculation and that of the financial institution were evaluated for reasonableness. See Note 6 – "Derivative Instruments" for further information.

Impairments. We review proved oil and gas properties for impairment when events and circumstances indicate a decline in the recoverability of the carrying value of such properties, such as a downward revision of the reserve estimates or lower commodity prices. We estimate the future cash flows expected in connection with the properties and compare such future cash flows to the carrying amounts of the properties to determine if the carrying amounts are recoverable. The factors used to determine fair value include, but are not limited to, estimates of proved and probable reserves, future commodity prices, the timing of future production and capital expenditures and a discount rate commensurate with the risk reflective of the lives remaining for the respective oil and gas properties. Because these significant fair value inputs are typically not observable, we classify impairments of long-lived assets as a level 3 fair value measure.

Asset Retirement Obligations. The initial measurement of asset retirement obligations at fair value is calculated using discounted cash flow techniques and based on internal estimates of future retirement costs associated with oil and gas properties. The factors used to determine fair value include, but are not limited to, plugging costs and reserve lives. Because these significant factors are typically not observable, we classify asset retirement obligations as a level 3 fair value measure.

Debt. The fair value of floating-rate debt is estimated to be equivalent to carrying amounts because the interest rates paid on such debt are set for periods of three months or less. See Note 9 – "Debt" for further information.

FASB guidance established a fair value hierarchy which prioritizes the inputs to valuation techniques used to measure fair value into three levels. The fair value hierarchy gives the highest priority to quoted market prices (unadjusted) in active markets for identical assets or liabilities (Level 1) and the lowest priority to unobservable inputs (Level 3). Level 2 inputs are inputs, other than quoted prices included within Level 1, which are observable for the asset or liability, either directly or indirectly. There have been no transfers between Level 1, Level 2 or Level 3.

Fair value information for financial assets and liabilities that are measured at fair value each reporting period is as follows at December 31, 2010:

	Total	Fair Value Measurements Using		
	Carrying Value	Level 1	Level 2	Level 3
Derivatives				
Crude oil swaps and collars	$ (3,283,427)	$ —	$ (3,283,427)	$ —
Natural gas swaps and collars	8,469,455	—	8,469,455	—
Interest rate swaps	(1,392,740)	—	(1,392,740)	—

Fair value information for financial assets and liabilities that are measured at fair value each reporting period is as follows at December 31, 2009:

	Total	Fair Value Measurements Using		
	Carrying Value	Level 1	Level 2	Level 3
Derivatives				
Crude oil & natural gas swaps	$ (191,579)	$ —	$ (191,579)	$ —
Crude oil & natural gas collars	15,096,160	—	15,096,160	—
Interest rate swaps	(4,610,469)	—	(4,610,469)	—

6. Derivative Instruments

At the end of each reporting period we record on our balance sheet the mark-to-market valuation of our derivative instruments. We recorded net assets for derivative instruments of $3.8 million and $10.3 million at December 31, 2010 and 2009, respectively. As a result of these agreements, we recorded a non-cash unrealized loss, for unsettled contracts, of $6.5 million, and of $23.9 million and a non-cash unrealized gain of $49.4 million for the years ended December 31, 2010, 2009 and 2008, respectively. The estimated change in fair value of the derivatives is reported in Other Income (Expense) as unrealized gain (loss) on derivative instruments. The realized gain (loss) on derivative instruments is included in natural gas and crude oil sales for our commodity hedges and as an (increase) decrease in interest expense for our interest rate swaps.

In the past we have entered into, and may in the future enter into, certain derivative arrangements with respect to portions of our natural gas and crude oil production, to reduce our sensitivity to volatile commodity prices, and with respect to portions of our debt, to reduce our sensitivity to volatile interest rates. None of our derivative instruments are designated as cash flow or fair value hedges. 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 commodity price and interest rate fluctuations. However, derivative arrangements limit the benefit of increases in the prices of natural gas, crude oil and natural gas liquids sales and limit the benefit of decreases in interest rates. Moreover, our derivative arrangements apply only to a portion of our production and our debt and provide only partial protection against declines in commodity prices and increases in interest rates, respectively. Such arrangements may expose us to risk of financial loss in certain circumstances. We continuously reevaluate our hedging programs in light of changes in production, market conditions, commodity price forecasts, capital spending, interest rate forecasts and debt service requirements.

We use a mix of commodity swaps and costless collars and interest rate swaps to accomplish our hedging strategy. Derivative assets and liabilities with the same counterparty, subject to contractual terms which provide for net settlement, are reported on a net basis on our consolidated balance sheets. We have exposure to financial institutions in the form of derivative transactions in connection with our hedges. These transactions are with counterparties in the financial services industry, and specifically with members of our bank group. These transactions could expose us to credit risk in the event of default of our counterparties. In addition, if any lender under our credit agreement is unable to fund its commitment, our liquidity could be reduced by an amount up to the aggregate amount of such lender's commitment under our credit agreement. We believe our counterparty risk is low in part because of the offsetting relationship we have with each of our counterparties provided for in our revolving credit agreement and various hedge contracts. See Note 5 — "Fair Value Measurements" for further information.

The following derivative contracts were in place at December 31, 2010:

Crude Oil		Volume/Month	Price/Unit	Fair Value
Jan 2011-Dec 2011	Swap	3,300 Bbls	$70.74	$ (909,114)
Jan 2011-Dec 2011	Collar	7,000 Bbls	$64.50-$69.50	(2,068,280)
Jan 2011 - Mar 2011	Swap	2,000 Bbls	$86.15	(28,124)
Apr 2011 - Jun 2011	Swap	1,500 Bbls	$86.78	(25,004)
Jul 2011- Sep 2011	Swap	500 Bbls	$87.32	(8,266)
Jan 2011 - Dec 2011	Swap	3,100 Bbls	$85.65	(244,639)
Natural Gas				
Jan 2011-Dec 2011	Collar	266,000 Mmbtu	$7.32-$8.70	8,904,646
Jan 2011 – Dec 2011	Swap	232,500 Mmbtu	$4.39	(435,191)
		Commodity price derivative instruments		5,186,028
Interest rate		**Notional Amount**	**Fixed Rate**	
Jan 2010-May 2011	Swap	$150,000,000	2.90%	(1,392,740)
		Interest rate derivative instruments		(1,392,740)
		Total net fair value asset of derivative instruments		$ 3,793,288

The following table details the effect of derivative contracts on the Consolidated Statements of Operations:

Contract Type	Location of Gain or (Loss) Recognized in Income	Amount of Gain or (Loss) Recognized in Income		
		Twelve Months Ended December 31,		
		2010	2009	2008
Natural gas contracts	Operating revenues	$ 19,465,873	$ 30,118,915	$ (793,052)
Crude oil contracts	Operating revenues	1,446,686	8,664,939	(8,517,005)
Interest rate	Interest expense	(4,594,968)	(4,432,364)	(3,988,231)
	Realized gain (loss)	$ 16,317,591	$ 34,351,490	$ (13,298,288)
Natural gas contracts	Other income (expense)	$ (8,241,131)	$ (7,544,562)	$ 21,362,595
Crude oil contracts	Other income (expense)	(1,477,423)	(17,393,075)	29,731,827
Interest rates	Other income (expense)	3,217,729	1,075,057	(1,685,461)
	Unrealized gain (loss)	$ (6,500,825)	$ (23,862,580)	$ 49,408,961

7. Accrued Liabilities

Accrued liabilities consist of the following:

	December 31,	
	2010	2009
Capital drilling and operating costs	$ 8,188,159	$ 2,018,250
Accrued compensation	2,857,000	1,200,000
Interest and loan fees	569,001	4,108,101
Equity offering costs	—	699,240
Other	1,185,016	826,719
	$ 12,799,176	$ 8,852,310

8. Asset Retirement Obligations

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

	December 31,	
	2010	2009
Balance beginning of year	$ 9,702,653	$ 13,068,542
Accretion expense	585,951	842,008
Liabilities incurred	59,178	105,289
Liabilities settled	(513,761)	(5,802,110)
Revisions	—	1,488,924
Balance end of year	$ 9,834,021	$ 9,702,653

During 2009, we disposed of $5.3 million of asset retirement liabilities assumed by the buyer as part of the sale of the Southwest Louisiana properties. Additional liabilities of $1.5 million were primarily recognized earlier in the year as revisions associated with increased retirement costs in the now sold Southwest Louisiana properties.

9. Debt

Revolving Credit Agreement

On May 8, 2007, we entered into a $400.0 million revolving credit agreement with Wells Fargo Bank, National Association, as agent, and the lender parties thereto, which amended and restated our revolving credit agreement dated as of July 15, 2005, as amended. Since that time, we have amended and restated this agreement as necessary. Our revolving credit agreement provides for aggregate borrowings of up to $400.0 million for acquisitions of crude oil and gas properties and for general corporate cash requirements. The revolving credit agreement includes usual and customary covenants for credit facilities of the respective types and sizes, 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 revolving credit agreement also contains certain financial covenants, including those currently requiring us to maintain (i) a ratio of current assets (including borrowing base availability and excluding derivative instruments) to current liabilities (excluding current portion of long-term debt and derivative instruments) of at least 1.0 to 1.0, (ii) the ratio of our total debt to Adjusted EBITDAX for any four trailing fiscal quarters which may not be greater than (a) 4.25 to 1.00 as of the end of any fiscal quarter through June 30, 2011, (b) 3.75 to 1.00 for the fiscal quarters ending September 30, 2011 and December 31, 2011, and (c) 3.50 to 1.00 thereafter, (iii) the ratio of Adjusted EBITDAX to cash interest expense for any four trailing fiscal quarters may not be less than (a) 2.00 through March 31, 2011, (b) 2.25 to 1.00 for the fiscal quarters ending June 30, 2011, September 30, 2011 and December 31, 2011, and (c) 2.50 for the quarters ending March 31, 2010 and June 30, 2012 and 2.75 to 1.00 thereafter, and (iv) the ratio of the sum of (a) the aggregate outstanding principal amount of the Loans under the revolver plus (b) the aggregate face amount of all undrawn and uncancelled Letters of Credit, plus the aggregate of all amounts drawn under all Letters of Credit and not yet reimbursed, as of such date to EBITDAX for the four fiscal quarters ending on such date to not be greater than 2.25 to 1.00. EBITDAX represents net income (loss) before net interest expense, taxes, and depreciation, amortization and exploration expenses. Adjusted EBITDAX, as defined in our credit agreements, represents EBITDAX as further adjusted for (i) unrealized gain or loss on derivative instruments, (ii) non-cash share-based compensation charges, (iii) impaired assets, (iv) other financing costs and (v) gains or losses on the disposition of assets, all of which will be required in determining our compliance with financial covenants under our revolving credit facility and second lien term loan agreement.

Borrowings under our revolving credit agreement are subject to a borrowing base limitation based on our proved crude oil and natural gas reserves. The borrowing base under our revolving credit agreement is currently $88.75 million. The next borrowing base re-determination is scheduled for May 1, 2011 and is subject to semi-annual redeterminations, although our lenders may elect to make one additional redetermination between scheduled redetermination dates. We may also issue up to $200 million in senior unsecured notes. Any such issuance of senior unsecured notes will reduce our borrowing base by 25% of the net proceeds from such issuance in excess of $150 million. Our revolving credit agreement also provides for the issuance of letters-of-credit up to a $5.0 million sub-limit. At December 31, 2010, no senior unsecured notes or letters-of-credit were outstanding. All principal amounts, together with all accrued and unpaid interest outstanding under our revolving credit agreement will be due and payable in full on May 31, 2013.

Advances under our revolving credit agreement are in the form of either base rate loans or LIBOR loans. The interest rate on the base rate loans fluctuates based upon the higher of the lender's "prime rate" and the Federal Funds rate. The interest rate on the LIBOR loans fluctuates based upon the rate at which Eurodollar deposits in the LIBOR market are quoted for the maturity selected. Pursuant to our revolving credit agreement, the applicable margin is between 2.75% and 3.50%, for LIBOR loans, and between 1.50% and 2.00%, for base rate loans. The specific interest margin applicable is determined by, in each case, the percent of the borrowing base utilized at the time of the credit extension. LIBOR loans of one, two, three and six months may be selected. The commitment fee payable on the unused portion of our borrowing base is 0.50%, which fee accrues and is payable quarterly in arrears.

At December 31, 2010, we had $4.0 million outstanding under our revolving credit agreement, with availability of $84.8 million.

Second Lien Credit Agreement

We entered into a new second lien credit agreement with Barclays Bank Plc, as agent, and the lender parties thereto which provided for term loans, made to us in a single draw, in an aggregate principal amount of $175 million on December 27, 2010. Our second lien credit agreement replaced our then existing $150 million second lien credit agreement with Credit Suisse, which was paid off in full and terminated at closing. Our second lien credit agreement matures on December 27, 2015.

Advances under our new second lien credit agreement are in the form of either base rate loans or LIBOR loans. The interest rate on the base rate loans fluctuates based upon the greatest of (i) 4.00% per annum, (ii) the "prime rate", (iii) the Federal Funds Effective Rate plus ½ of 1% and (iv) the LIBO rate for a one month interest period plus 1.00%. The applicable margin for base rate loans is 8.50%. The interest rate on the LIBOR loans fluctuates based upon the higher of (i) 3.0% per annum and (ii) the LIBOR rate per annum. The applicable margin for LIBOR loans is 9.50%.

In addition to certain of the revolving credit agreement covenants described above, the second lien credit agreement also requires the ratio of PV-10 Value to total Net Debt to be greater than 1.25 to 1.00 as of the end of the second and fourth calendar quarters through June 30, 2012 and 1.50 to 1.00 thereafter. The PV-10 Value represents the present value of estimated future revenues less severance and ad valorem taxes, operating, gathering, transportation and marketing expenses and capital expenditures from the production of proved reserves on our oil and gas properties as set forth in the most recent reserve reports.

At December 31, 2010, we had a principal amount of $175.0 million outstanding under our second lien credit agreement, with a discount of $7.0 million using the estimated market value interest rate at the time of issuance, for a net balance of $168.0 million.

Promissory Notes

On November 6, 2009, we issued an unsecured promissory note in an aggregate principal amount of $10.0 million to Wells Fargo Bank, National Association, the administrative agent and a lender under our revolving credit agreement. All of the proceeds of this promissory note were used to repay indebtedness outstanding under our revolving credit agreement. As support for the contingent obligation to purchase this promissory note, should it not be repaid at maturity, Oaktree Holdings, a related party, deposited $10.0 million in escrow for the benefit of Wells Fargo Bank, National Association.

On December 22, 2009, we repaid this $10.0 million unsecured promissory note with proceeds from our equity offering and Oaktree Holdings' $10.0 million deposit in escrow was released back to Oaktree Holdings from Wells Fargo Bank, National Association. All $1.7 million debt issuance costs associated with the issuance of the $10.0 million promissory note were expensed in conjunction with the repayment of the $10.0 million promissory note.

As consideration for Oaktree Holdings' agreement to deposit $10.0 million in escrow as described above, we issued an unsecured subordinated promissory note on November 6, 2009 in an aggregate principal amount of $2.0 million to Oaktree Holdings. The indebtedness under the promissory note bore interest at a per annum rate equal to 8.0% and matured on the later of (i) November 8, 2012 and (ii) the date six months after payment in full in cash of all Obligations (as such term is defined under our credit agreements), and the termination of all commitments to extend credit under our credit agreements. The promissory note was subordinated in right of payment to the prior payment in full in cash of all obligations under our credit agreements. On December 27, 2010, we paid off this $2.0 million subordinated promissory note in conjunction with proceeds from our new second lien credit agreement.

Summary

At December 31, 2010, we were in compliance with the covenants under our revolving credit agreement and second lien credit agreement.

Our revolving credit agreement and our second lien credit agreement are secured by liens on substantially all of our assets, including the capital stock of our subsidiaries. The liens securing the obligations under our second lien credit agreement are junior to those under our revolving credit agreement. Unpaid interest is payable under our credit agreements as borrowings mature and renew.

We constructively fixed the interest rate on $150.0 million of our variable rate debt by entering into interest rate swaps at a weighted average swap price of 2.9%.

Our debt consists of the following:

	December 31, 2010	December 31, 2009
Revolving Credit Agreement (interest rate in effect at December 31, 2010 was 3.75%)	$ 4,000,000	$ 41,000,000
Second Lien Credit Agreement (interest rate in effect at December 31, 2010 was 12.50%)	175,000,000	—
Second Lien Credit Agreement (paid off in December 2010)	—	150,000,000
Subordinated Promissory Note, (paid off in December 2010)	—	2,000,000
Notes payable to finance vehicles, (paid off in 2010)	—	19,014
	179,000,000	193,019,014
Less: current portion	—	(19,014)
unamortized debt discount	(6,986,510)	(250,249)
Total long-term debt	$ 172,013,490	$ 192,749,751

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

	Long-Term Debt
2011	$ —
2012	—
2013	4,000,000
2014	—
2015	175,000,000
	$ 179,000,000

10. Commitments and Contingencies

Lease Obligations

We currently lease and sublease, through January 31, 2014, 54,939 square feet of executive and corporate office space located at 717 Texas Avenue in downtown Houston, Texas. Total general and administrative rent expense for the years ended December 31, 2010, 2009 and 2008, was approximately $1.1 million, $2.2 million and $1.4 million, respectively. Effective January 1, 2010, we subleased to a subtenant 27,144 square feet of this space for a total rental of approximately $86,000 per month through September 30, 2011. The sublease rent has been accounted for as a reduction to rent expense. We have entered into various vehicle leases for periods ranging from 12 to 24 months. These contracts will expire at various times with the latest contract expiring in November 2012. We also have various other equipment leases that expire in 12 months, with the latest contract expiring in August 2011. Total operational rent expense for the years ended December 31, 2010, 2009 and 2008, were approximately $2.3 million, $3.0 million and $3.4 million, respectively.

The following table provides information about our total operating lease obligations as of December 31, 2010:

		Operating leases
2011	$	1,527,859
2012		1,448,744
2013		1,419,933
2014		118,328
2015		—
Thereafter		—
Total	$	4,514,864

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. During the second quarter of 2009, holders of oil and gas leases in East Texas (Haynesville Shale) filed two causes of action against us alleging breach of contract for not paying lease bonuses on certain oil and gas leases pursued by our leasing agent. The damages alleged are approximately $2.4 million and there is approximately $300,000 in written demands from other holders of leases in this area that we believe may contemplate legal proceedings. We are vigorously defending these lawsuits, and believe we have meritorious defenses. We do not believe that these claims will have a material adverse effect on our business, financial position, results of operations or cash flows, although we cannot guarantee that a material adverse effect will not occur.

In November 2010, we were named in a lawsuit filed by a current non-operating working interest partner that asserts that he owns a larger working interest in a field than previously recognized by us, and by predecessor operators to which we have granted indemnification rights. In dispute is whether ownership rights in specific depths were transferred through a number of decade-old poorly documented transactions. The maximum amount asserted in the suit filed could be determined at up to $4.7 million. We are vigorously defending this lawsuit, and believe we have meritorious defenses. We currently do not believe that this claim will have a material adverse effect on our business, financial position, results of operations or cash flows, although we cannot guarantee that a material adverse effect will not occur.

Employment Agreements

In December 2008, we entered into amended and restated 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 executive officer elects not to extend the agreement. These agreements provide for an annual base salary of $370,000 and $340,000, respectively, subject to increases at the discretion of the Compensation Committee. 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 2.99 times the sum of the current calendar year's base salary plus prior year's annual cash incentive bonus, health insurance benefits for 36 months and acceleration to 100% vested status for all stock, stock option and other equity awards.

Also in December 2008, we entered into amended and restated employment agreements with our three other Senior Vice Presidents and entered into an employment agreement with our one Vice President. Each agreement has a term of two years with automatic yearly extensions unless we or the executive officer elects not to extend the agreement. These agreements provide for an annual base salary ranging from $186,300 to $220,000, subject to increases at the discretion of the Compensation Committee. 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 two times current year base salary plus prior year bonus, health insurance benefits for 24 months and acceleration to 100% vested status for all stock, stock option and other equity awards. In October 2010, our Vice President terminated his employment without good reason and therefore the agreement entered into with us was cancelled.

In May 2010, we entered into an employment agreement with a new Senior Vice President. This agreement has a term of two years with automatic yearly extensions unless we or the executive officer elects not to extend the agreement. This agreement provides for an initial base salary of $230,000 per year, subject to increases at the discretion of the Compensation Committee. 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 two times current year base salary plus prior year bonus, health insurance benefits for 24 months and acceleration to 100% vested status for all stock, stock option and other equity awards.

11. Stockholders' Equity

	2010	2009
Common Stock		
Par value $0.001; 200,000,000 shares authorized; 44,952,405 and 38,578,204 shares issued and 44,857,259 and 38,516,658 shares outstanding as of December 31, 2010 and 2009, respectively	$ 44,952	$ 38,578
Treasury Stock		
At cost, 95,146 and 61,546 shares as of December 31, 2010 and 2009, respectively	$ (495,942)	$ (384,312)

All classes of preferred stockholders had a liquidation preference over common stockholders of $500 per preferred share, plus accrued dividends. On December 22, 2009, all shares of preferred stock, including accumulated dividends, were converted into Common Stock in conjunction with our equity offering.

12. Share-Based Compensation

As of December 31, 2010, we had share-based compensation, which includes both stock options and restricted stock awarded to employees and directors that were either performance related or granted upon initial employment.

Incentive Plans

In the third quarter 2008, our Board of Directors formally adopted an amendment to our performance based cash bonus plan and adopted a new performance based long term stock bonus plan for the benefit of all employees - the Crimson Cash Incentive Bonus Plan (*"CIBP"*) and the Crimson Long-Term Incentive Plan (*"LTIP"*), respectively. Both plans, and specific targeted performance measures for the fiscal year 2008 under those plans, were previously approved by the Compensation Committee. Upon achieving the established performance levels, bonus awards were calculated as a percentage of base salary for the plan year. The plan awards were disbursed in the first quarter of the following year. Employees must have been employed by us at the time that final plan awards were dispersed to have been eligible.

The CIBP awards were paid out in cash (*"Cash Awards"*). The performance targets were evaluated on a quarterly basis and used to estimate the approximate expense earned to date. Approximately $1.2 million was recognized as compensation expense related to the Cash Awards for the twelve months ended December 31, 2008. The Board of Directors suspended the CIBP for 2009. However, discretionary cash bonus awards of approximately $1.2 million were approved by the Board of Directors for fiscal year 2009 and were paid in March 2010. The CIBP was reinstated by the Board of Directors for fiscal year 2010. Approximately $2.9 million was recognized as compensation expense related to the Cash Awards for the twelve months ended December 31, 2010 and was paid in March 2011.

The LTIP bonus awards were paid half in the form of restricted Common Stock and half in the form of stock options (*"Stock Awards"*). The Stock Awards vest 25% per year, over the first through fourth anniversaries from the date of grant, at which time 100% of all Stock Awards will be vested. The number of shares of restricted Common Stock and the number of shares underlying the stock options granted as Stock Awards were determined based upon the fair market value of the Common Stock on the date of the grant in the first quarter 2009. The fair value of the stock options to be awarded as part of this plan was determined through use of the Black-Scholes valuation model. The Stock Awards granted pursuant to this plan were granted under the existing amended and restated 2005 Stock Incentive Plan. The Board of Directors and holders of a majority of those shares entitled to vote, approved; among other things, an increase in the number of available shares of Common Stock issuable under the amended and restated 2005 Stock Incentive Plan of 1.0 million shares.

In March 2009, the Board of Directors approved the awarding of approximately 1.1 million shares to our employees under the LTIP for the 2008 calendar year. Due to the decline in our stock price, the Board of Directors suspended the LTIP in 2009. The LTIP has not yet been reinstated.

Stock Options

On February 28, 2005, we established our 2005 Stock Incentive Plan (*"2005 Plan"*) and authorized the issuance of up to approximately 2.9 million shares of Common Stock pursuant to awards under the plan. In the third quarter 2008, our Board of Directors and a majority of our stockholders approved an amendment and restatement of our 2005 Stock Incentive Plan that provided for an increase in the number of shares of Common Stock available for award under our 2005 Stock Incentive Plan to approximately 3.9 million shares. We also issued 250,000 shares of restricted Common Stock to our executive officers outside of these plans. Approximately 1.7 million (1.3 million vested) stock options and 1.3 million unvested restricted shares were outstanding at December 31, 2010. Option awards outstanding have exercise prices ranging from $2.33 to $13.25 per share. In 2010 and 2009, respectively, 326,364 and 127,243 shares of restricted Common Stock vested, of which 33,600 and 40,921 shares were withheld by us to satisfy the employees' tax liability resulting from the vesting of these shares, as provided for in the restricted stock agreement, with the remaining shares being released to the employees and associated directors. At December 31, 2010, we had approximately 0.4 million shares of Common Stock available for future grant under the 2005 Plan.

For stock options, we recorded $0.3 million, $1.1 million and $4.9 million in expense (included on the Consolidated Statements of Operations in general and administrative expense) for the years ended December 31, 2010, 2009 and 2008, respectively, and an estimated $0.7 million will be expensed over the remaining vesting period.

The fair value of each option award is estimated on the date of grant using the Black-Scholes option pricing model. Assumptions used in the valuation are disclosed in the following table. Expected volatilities are based on historical volatility of our stock with a look back period based on the expected term. The expected dividend yield is zero as we have never declared dividends on our Common Stock. The expected term of options granted represents the period of time that the options are expected to be outstanding. The risk-free rate is based on U.S. Treasury bills with a duration equal or close to the expected term of the options at the time of grant. The forfeiture rates are based on historical forfeitures.

	2010	**2009**	**2008**
Weighted average fair value of awards	$ 2.19	$ 1.41	$ 7.07
Pre-vest forfeiture rate	5.01%	3.62%	None
Average grant price	$ 3.19	$ 2.40	$ 12.29
Expected volatility	75.38%	60.98%	58.61%
Risk-free rate	2.55%	2.48%	3.38%
Expected dividend yields	None	None	None
Expected term (in years)	6.36	6.25	6.0

The following table summarizes stock option activity for the three years ended December 31, 2010:

	Number of Shares Underlying Options	Weighted Average Exercise Price	Intrinsic Value
Outstanding at December 31, 2007	2,730,300	$ 12.76	
Granted	126,500	12.29	
Exercised	(75,000)	5.02	$ 512,580
Expired	(27,000)	8.86	
Exchanged	(1,091,260)	17.00	
Outstanding at December 31, 2008	1,663,540	10.39	
Granted	488,660	2.40	
Exercised	—	—	$ —
Cancelled/forfeited	(166,371)	6.20	
Expired	(28,300)	5.56	
Outstanding at December 31, 2009	1,957,529	8.82	
Granted	179,500	3.19	
Exercised	(28,381)	2.40	$ 25,208
Cancelled/forfeited	(361,105)	6.48	
Expired	(16,000)	4.50	
Outstanding at December 31, 2010	1,731,543	8.87	$ 683,474
Exercisable at December 31, 2010	1,287,305	10.60	$ 133,994

Restricted Stock Awards

For restricted stock awards, we recorded $1.5 million, $1.3 million and $0.5 million in expense (included on the Consolidated Statements of Operations in general and administrative expense) for the years ended December 31, 2010, 2009 and 2008, respectively and an estimated $3.0 million will be expensed over the remaining vesting period.

In 2010, we issued 402,859 shares of unvested Common Stock, pursuant to restricted stock awards under the LTIP for the 2008 calendar year, of which 22,000 were subsequently forfeited. The restricted stock will vest over a four year period. We also issued 31,646 shares of Common Stock pursuant to restricted stock awards to two members of our board of directors as compensation pursuant to the Director Compensation Plan. The fair value of the unvested Common Stock was calculated as approximately $1.2 million on the grant date and will be amortized over the vesting period.

In 2009, we issued 648,936 shares of unvested Common Stock, pursuant to restricted stock awards under the LTIP for the 2008 calendar year, of which 36,366 were subsequently forfeited. The restricted stock will vest over a four year period. The fair value of the unvested Common Stock was calculated as approximately $1.6 million on the grant date and will be amortized using the straight-line method over the vesting period. We also issued 48,586 shares of Common Stock pursuant to restricted stock awards to two members of our board of directors as compensation pursuant to the Director Compensation Plan.

In the fourth quarter 2008, we issued 12,280 shares of unvested Common Stock, pursuant to restricted stock awards in exchange for the forfeiture of 24,560 substantially unvested stock option grants. The fair value of the unvested Common Stock was calculated as approximately $88,000 on the issuance date. The fair value of the forfeited stock options, calculated using the Black-Scholes valuation model, was approximately $37,000 immediately prior to the forfeiture. The sum of the incremental value of the new award over the forfeited options, approximately $52,000, and the unrecognized compensation cost for the original award as of the exchange date, approximately $45,000 are being amortized using the straight line method over the new vesting period of five years, or approximately $1,600 a month.

In the third quarter 2008, we issued 1,538 shares of Common Stock pursuant to restricted stock awards to two members of our board of directors as compensation pursuant to the Director Compensation Plan. In the third quarter 2008, we also issued 533,350 shares of unvested Common Stock pursuant to restricted stock awards in exchange for the forfeiture of 1,066,700 substantially vested stock option grants. The fair value of the unvested Common Stock was calculated as $4.9 million on the issuance date. The fair value of the forfeited stock options, calculated using the Black-Scholes valuation model, was $4.3 million immediately prior to the forfeiture. The sum of the incremental value of the new award over the forfeited options, $0.6 million, and the unrecognized compensation cost for the original award as of the exchange date, $1.4 million, are being amortized using the straight line method over the new vesting period of five years, or approximately $32,000 a month.

Restricted stock activity for the three years ended December 31, 2010 is summarized below:

	Shares	Weighted-Average Grant Date Fair Value
Non-vested as of January 1, 2008	252,818	$ 7.35
Granted	547,168	9.12
Vested	(85,318)	7.34
Non-vested as of December 31, 2008	714,668	8.70
Granted	697,522	2.49
Vested	(127,243)	5.49
Cancelled/forfeited	(36,366)	2.40
Non-vested as of December 31, 2009	1,248,581	3.41
Granted	434,505	3.09
Vested	(326,364)	3.71
Cancelled/forfeited	(88,685)	2.53
Non-vested as of December 31, 2010	1,268,037	3.28

Certain of these restricted stock awards were issued separately from the 2005 Plan.

13. Income (Loss) Per Common Share

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

	2010	2009	2008
Net income (loss)	$ (30,844,897)	$ (34,069,990)	$ 46,203,218
Preferred stock dividends	—	(4,522,645)	(4,234,050)
Net income (loss) available to common stockholders	$ (30,844,897)	$ (38,592,635)	$ 41,969,168
Weighted-average number of shares of Common Stock – basic (denominator)	39,397,486	7,861,054	5,371,377
Income (loss) per share - basic	$ (0.78)	$ (4.91)	$ 7.81
Weighted-average number of shares of Common Stock – diluted (denominator)	39,397,486	7,861,054	10,360,348
Income (loss) per share – diluted	$ (0.78)	$ (4.91)	$ 4.46

The numerator for basic earnings per share is income (loss) available to common stockholders. The numerator for diluted earnings per share is net income in 2008 and net loss available to common stockholders in 2009 and 2010, due to antidilution.

Potential dilutive securities (stock options, stock warrants and convertible preferred stock) in 2009 and 2010 have not been considered since we reported a net loss and, accordingly, their effects would be antidilutive. The potentially dilutive shares would have been 4,770,404 shares and 95,967 shares in 2009 and 2010, respectively.

14. Supplementary Disclosures of the Consolidated Statements of Cash Flows

The following table sets forth non-cash investing and financing activities for the three years ended December 31,:

	2010	2009	2008
Liabilities released on property dispositions	$ 351,092	$ 5,309,005	$ —
Conversion of preferred stock dividends	—	(18,753,649)	(63,387)
Promissory note, net of discount [1]	—	(1,749,751)	—

(1) See Note 9 "Debt —Promissory Note" for further information.

15. Income Taxes

Income tax benefit (expense) for 2010, 2009 and 2008 consist of the following:

	2010	2009	2008
Current tax benefit (expense)	$ —	$ 122,162	$ (574,752)
Deferred tax benefit (expense)	16,607,139	16,572,200	(26,116,055)
Income tax benefit (expense)	$ 16,607,139	$ 16,694,362	$ (26,690,807)

The following is a reconciliation of effective income tax rates by applying the federal statutory rate of 35% to the income and loss for the years ended December 31, 2010, 2009 and 2008, respectively:

	2010	2009	2008
Income (Loss) Before Income Taxes	$ (47,452,036)	$ (50,764,352)	$ 72,894,025
Income Tax Benefit (Expense) at Statutory Rate	$ 16,608,213	$ 17,767,523	$ (25,512,909)
Adjustment to NOL carryforward	(261,154)	(1,562,704)	—
Effect for Permanent Items	(23,699)	(4,002)	(307,425)
State Taxes and Other	283,779	493,545	(870,473)
Income Tax Benefit (Expense)	$ 16,607,139	$ 16,694,362	$ (26,690,807)

As of December 31, 2010, we had total net operating loss carryforwards of approximately $98.6 million, which are available to reduce future taxable income and the related income tax liability; however, 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 beginning in 2011 and ending in 2031.

Significant components of our deferred tax assets and liabilities are as follows:

	December 31, 2010	December 31, 2009
Deferred tax assets		
Net operating loss carryforwards	$ 34,902,077	$ 22,512,115
Income tax credits	283,789	283,789
Deferred compensation	6,486,831	5,897,291
Other	(213,305)	204,613
Deferred tax assets before valuation allowance	41,459,392	28,897,808
Valuation allowance	(3,387,923)	(3,260,875)
Net deferred tax assets	38,071,469	25,636,933
Deferred tax liabilities		
Oil and gas properties	(27,874,074)	(29,467,705)
Derivative instruments	(1,187,277)	(3,537,551)
Deferred tax liabilities	(29,061,351)	(33,005,256)
Net deferred tax assets (liabilities)	$ 9,010,118	$ (7,368,323)

In assessing the realizability of deferred tax assets, we consider whether it is more likely than not that some portion or all of the deferred tax assets will not be realized. The ultimate realization of deferred tax assets is dependent upon the generation of future taxable income during the periods in which those temporary differences become deductible. We consider the scheduled reversal of deferred tax liabilities, projected future taxable income and tax planning strategies in making this assessment. Based upon the level of historical taxable income and projections for future taxable income over the periods in which the deferred tax assets are deductible, we believe it is more likely than not that we will realize the benefits of these deductible differences net of a tax-adjusted $3.4 million valuation allowance. The amount of the deferred tax assets considered realizable could be reduced in the future if estimates of future taxable income during the carryforward period are reduced.

ASC 740, *Income Taxes* (*"ASC 740"*) prescribes a recognition threshold and a measurement attribute for the financial statement recognition and measurement of income tax positions taken or expected to be taken in an income tax return. For those benefits to be recognized, an income tax position must be more-likely-than-not to be sustained upon examination by taxing authorities. There was not a material impact on our operating results, financial position or cash flows as a result of the adoption of the provisions of ASC 740. A reconciliation of the beginning and ending amount of unrecognized income tax benefits is as follows:

	Unrecognized Tax Benefits
Balance at December 31, 2009	$ 518,219
Additions based on tax positions related to the current year	—
Additions based on tax positions related to prior years	—
Additions due to acquisitions	—
Reductions due to a lapse of the applicable statute of limitations	—
Balance at December 31, 2010	$ 518,219

Generally, our income tax years of 2006 through the current year remain open and subject to examination by Federal tax authorities or the tax authorities in Texas, Louisiana and Colorado which are the jurisdictions where we have our principal operations. These audits can result in adjustments of taxes due or adjustments of the net operating loss carryforwards that are available to offset future taxable income.

Our policy is to recognize interest and penalties related to uncertain tax positions as income tax benefit (expense) in our Consolidated Statements of Operations. For the years ended December 31, 2010 and 2009, respectively, we recorded no interest expense and penalties related to unrecognized tax benefits associated with uncertain tax positions recognized in our provision for income taxes.

The total amount of unrecognized tax benefit if recognized that would affect the effective tax rate was zero.

Our tax returns are subject to periodic audits by the various jurisdictions in which we operate. These audits can result in adjustments of taxes due or adjustments of the net operating loss carryforwards that are available to offset future taxable income.

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, 2011. 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.

16. Quarterly Results (Unaudited)

Summary data relating to the results of operations for each quarter for the years ended December 31, 2010 and 2009 follows:

	Three Months Ended			
	March 31	June 30	September 30	December 31
2010				
Net revenues	$ 22,609,859	$ 21,452,943	$ 24,535,907	$ 27,943,258
Income (loss) from operations	1,195,435	402,731	1,714,557	(17,627,620)
Net income (loss) available to common stockholders	208,815	(6,370,850)	(3,819,908)	(20,862,954)
Income(loss)per common share (1)				
Basic	$ 0.01	$ (0.16)	$ (0.10)	$ (0.50)
Diluted	$ 0.01	$ (0.16)	$ (0.10)	$ (0.50)
Weighted average shares outstanding				
Basic	38,506,160	38,635,725	38,819,780	42,113,808
Diluted	38,653,645	38,635,725	38,819,780	42,113,808
2009				
Net revenues	$ 30,730,867	$ 28,619,937	$ 26,900,404	$ 26,196,438
Income (loss) from operations	3,004,219	2,262,485	3,533,485	(9,188,025)
Net income (loss) available to common stockholders	3,952,884	(14,380,332)	(9,742,289)	(18,422,898)
Income(loss)per common share (1)				
Basic	$ 0.66	$ (2.24)	$ (1.51)	$ (1.86)
Diluted	$ 0.46	$ (2.24)	$ (1.51)	$ (1.86)
Weighted average shares outstanding				
Basic	6,026,888	6,421,225	6,444,013	9,907,024
Diluted	10,856,219	6,421,225	6,444,013	9,907,024

(1) Quarterly income (loss) per share is based on the weighted average number of shares outstanding during the quarter. Because of changes in the number of shares outstanding during the quarters, due to the exercise of stock options and issuance of common stock, the sum of quarterly earnings per share may not equal earnings per share for the year.

17. Oil and Gas Reserves (unaudited)

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 beginning with 2009 are based on an unweighted 12-month average of the first-day-of-the-month price for the period January through December 2009 held constant throughout the life of the properties. 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.

The following unaudited table sets forth proved natural gas, crude oil and natural gas liquids reserves, all within the United States, at December 31, 2010, 2009 and 2008, 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.

	Natural Gas (MMcf)	Crude Oil (MBbls)	Natural Gas Liquids (MBbls)	Total (Mcfe)
QUANTITIES OF PROVED RESERVES:				
Balance December 31, 2007	91,239	2,903	3,590	130,198
Revisions (2)	(9,679)	(408)	(753)	(16,642)
Extensions, discoveries and additions	11,949	471	603	18,394
Purchase	17,312	107	475	20,804
Sales (3)	(1,516)	(11)	—	(1,585)
Production	(13,136)	(498)	(516)	(19,223)
Balance December 31, 2008	96,169	2,564	3,399	131,946
Revisions	(11,753)	139	(179)	(11,994)
Extensions, discoveries and additions	1,901	—	—	1,902
Sales (3)	(6,043)	(412)	(153)	(9,434)
Production	(10,414)	(327)	(426)	(14,931)
Balance December 31, 2009	69,860	1,964	2,641	97,489
Revisions	12,654	137	341	15,526
Extensions, discoveries and additions	62,527	335	337	66,559
Sales (3)	(80)	(12)	—	(151)
Production	(9,286)	(260)	(346)	(12,925)
Balance December 31, 2010	135,675	2,164	2,973	166,498
PROVED DEVELOPED RESERVES:				
December 31, 2008	66,712	1,616	2,423	90,945
December 31, 2009	49,075	1,274	1,977	68,581
December 31, 2010	60,325	1,403	1,898	80,130
PROVED UNDEVELOPED RESERVES:				
December 31, 2008	29,457	948	976	41,002
December 31, 2009	20,784	690	664	28,907
December 31, 2010	75,350	761	1,075	86,368

(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 2007 volumes for natural gas and natural gas liquids are reflected in revisions.

(2) Periodic revisions to the estimated reserves and future cash flows may be necessary as a result of a number of factors, including reservoir performance, new drilling, oil and natural gas prices, cost changes, technological advances, new geological or geophysical data, or other economic factors.

(3) Sales are calculated based on the beginning of the year reserves adjusted for current year production with no adjustment for revisions.

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

	2010	2009	2008
Future cash inflows	$ 860,655,250	$ 475,007,800	$ 749,121,400
Future production and development costs			
Production	(218,221,203)	(156,581,500)	(214,969,100)
Development	(195,819,078)	(55,021,500)	(86,068,300)
Future cash flows before income taxes	446,614,969	263,404,800	448,084,000
Future income taxes	(37,624,289)	—	(46,695,950)
Future net cash flows after income taxes	408,990,680	263,404,800	401,388,050
10% annual discount for estimated timing of cash flows	(182,476,004)	(86,982,100)	(140,485,818)
Standardized measure of discounted future net cash flows	$ 226,514,676	$ 176,422,700	$ 260,902,233

Our calculations of the standardized measure of discounted future net cash flows include the effect of estimated future income tax expenses for all years reported. At December 31, 2009, the future pretax net cash flows from our proved oil and gas reserves are estimated to be less than the sum of the tax basis of the applicable producing properties and our available net operating loss (*"NOLs"*) carryforward; therefore, there was zero future tax benefit or expense at December 31, 2009. We believe it is more likely than not that all of our total available NOLs will be realized within the appropriate carryforward period. Our operations and all NOLs are attributable to our oil and gas assets.

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

	2010	2009	2008
Beginning of year	$ 176,422,700	$ 260,902,233	$ 399,523,079
Changes from:			
Purchases of proved reserves	—	—	69,628,594
Sales of producing properties	(408,190)	(25,350,512)	(2,817,597)
Extensions, discoveries and improved recovery, less related costs	109,361,697	3,864,603	77,931,000
Sales of natural gas, crude oil and natural gas liquids produced, net of production costs	(53,956,677)	(48,528,840)	(157,899,050)
Revision of quantity estimates[1]	9,476,255	(26,277,363)	(44,029,057)
Accretion of discount	17,642,270	29,094,980	39,952,308
Change in income taxes	(13,206,215)	30,352,367	101,522,054
Changes in estimated future development costs	(11,801,896)	14,712,798	(32,461,195)
Development costs incurred that reduced future development costs	11,788,100	7,085,480	20,342,054
Change in sales and transfer prices, net of production costs	(1,102,871)	(64,108,501)	(218,421,676)
Changes in production rates (timing) and other	(17,700,499)	(5,324,545)	7,631,719
End of year	$ 226,514,676	$ 176,422,700	$ 260,902,233

(1) Periodic revisions to the quantity estimates may be necessary as a result of a number of factors, including reservoir performance, new drilling, oil and natural gas prices, cost changes, technological advances, new geological or geophysical data, or other economic factors.

This disclosure excludes the effects of realized hedges ($20,912,559 gain in 2010; $38,783,854 gain in 2009; $9,310,057 loss in 2008) which are included in natural gas and crude oil sales on the statements of operation.

18. Subsequent Event

On February 18, 2011, we completed an option exchange program (the “Exchange Program”) pursuant to which we exchanged outstanding options, each representing the right to purchase shares of our common stock, par value $0.001 per share (the “Common Stock”), granted under our 2005 Stock Incentive Plan (the “2005 Plan”) with an exercise price greater than $5.00 per share, vested and unvested (the “Eligible Options”), for new options to purchase Common Stock (the “New Options”).

The Exchange Program was effected with certain employees, including each of our named executive officers. Under the Exchange Program, a total of 1,093,240 Eligible Options with a weighted average exercise price of $11.24 per share were exchanged for 1,093,240 New Options with an exercise price of $5.00 per share. The table below sets forth the number of Eligible Options exchanged for an equivalent number of New Options and the weighted average exercise price of such Eligible Options held by each of our named executive officers.

	Eligible Options	Weighted Average Exercise Price
Allan D. Keel	500,000	$11.97
E. Joseph Grady	225,000	$11.38
Thomas H. Atkins	38,300	$11.60
Jay S. Mengle	45,000	$11.60
Tracy Price	90,000	$11.60
Total	898,300	$11.75

The Closing Price of the Common Stock on February 22, 2011 was $3.98; therefore, under the terms of the Exchange Program, the exercise price of the New Options was fixed at $5.00 per share. All of the New Options will be subject to a vesting schedule providing for 25% of the New Options to vest annually over the first four years following February 18, 2011.

Due to an annual limitation in the number of options to purchase Common Stock that may be issued under the 2005 Plan, Allan D. Keel, our Chief Executive Officer, was limited to exchanging only the portion of Eligible Options held by him that was not in excess of such annual limitation. We may offer to exchange at a later date the remaining 175,000 Eligible Options that are held by Mr. Keel, and which have a weighted average exercise price of $9.70.

The fair value of the Eligible Options exchanged, calculated using the Black-Scholes valuation model, was $1.8 million immediately prior to the exchange. The fair value of the New Options was calculated at $2.7 million. Therefore, the $0.9 million incremental value of the New Options over the Eligible Options and the unrecognized compensation cost for the original award as of the exchange date of $0.2 million, or $1.1 million, is being amortized using the straight line method over the new vesting period of four years, or approximately $22,000 a month.

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

Board of Directors and
Stockholders of Crimson Exploration Inc.

We have audited in accordance with the standards of the Public Company Accounting Oversight Board (United States) the consolidated financial statements of Crimson Exploration Inc. and subsidiaries referred to in our report dated March 18, 2011, which is included in the annual report to stockholders. Our audits of the consolidated financial statements included the financial statement schedule listed in the index appearing under Item 15(2), which is the responsibility of the Company’s management. In our opinion, this financial statement schedule, when considered in relation to the consolidated financial statements taken as a whole, presents fairly, in all material respects, the information set forth therein.

/s/ GRANT THORNTON LLP

Houston, Texas
March 18, 2011

CRIMSON EXPLORATION INC. AND SUBSIDIARIES
SCHEDULE II – VALUATION AND QUALIFYING ACCOUNTS
FOR THE YEARS ENDED DECEMBER 31, 2010, 2009 and 2008

DESCRIPTION	BALANCE AT BEGINNING OF PERIOD	PROVISIONS/ ADDITIONS	RECOVERIES/ DEDUCTIONS	BALANCE AT END OF PERIOD
For the year ended December 31, 2008:				
Allowance for doubtful accounts	$ 215,015	—	—	$ 215,015
Valuation allowance for deferred tax assets	$ 3,442,034	—	(181,159)	$ 3,260,875
For the year ended December 31, 2009:				
Allowance for doubtful accounts	$ 215,015	239,676	(43,367)	$ 411,324
Valuation allowance for deferred tax assets	$ 3,260,875	—	—	$ 3,260,875
For the year ended December 31, 2010:				
Allowance for doubtful accounts	$ 411,324	167,819	—	$ 579,143
Valuation allowance for deferred tax assets	$ 3,260,875	127,048	—	$ 3,387,923