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, 2012
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:

Title of each class	Name of each exchange on which registered
Common Stock, $0.001 par value per share	NASDAQ Global Market

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

Indicate by check mark if the Registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act. Yes ☐ 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 whether the Registrant has submitted electronically and posted on its corporate website, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T during the preceding 12 months (or for such shorter period that the Registrant was required to submit and post such files). 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, 2012, the aggregate market value of the Registrant’s common stock held by non-affiliates of the Registrant was $99,420,433 based on the closing sales price of $4.59 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 1, 2013, there were 46,063,822 shares of common stock outstanding.

DOCUMENTS INCORPORATED BY REFERENCE

Portions of our Definitive Proxy Statement for the 2013 Annual Meeting, expected to be filed within 120 days of our fiscal year-end, are incorporated by reference into Part III of this Form 10-K.

TABLE OF CONTENTS

PART I

PART II

PART III

PART IV

CAUTIONARY STATEMENTS REGARDING FORWARD-LOOKING STATEMENTS

Certain statements contained in or incorporated by reference into this Annual Report on Form 10-K or other filings with the SEC and our public releases, including, but not limited to, information regarding the status and progress of our operating activities, the plans and objectives of our management, assumptions regarding our future performance and plans, and any financial guidance provided therein may constitute forward-looking statements within the meaning of Section 27A of the Securities Act of 1933 and Section 21E of the Securities Exchange Act of 1934. These forward-looking statements include information concerning future production and reserves, schedules, plans, timing of development, contributions from crude oil and natural gas properties, and also include those statements accompanied by or that otherwise include the words “may,” “could,” “believes,” “expects,” “anticipates,” “intends,” “estimates,” “projects,” “predicts,” “target,” “goal,” “plans,” “objective,” “potential,” “should,” or similar expressions or variations on such expressions that convey the uncertainty of future events or outcomes. These forward-looking statements are made subject to certain risks and uncertainties that could cause actual results to differ materially from those stated. Risks and uncertainties (some of which are beyond our control) that could cause or contribute to such differences include, without limitation, those discussed in the section entitled “Risk Factors” included in this Annual Report on Form 10-K.

Any of these factors and other factors contained in this Annual Report on Form 10-K could cause our actual results to differ materially from the results implied by these or any other forward-looking statements made by us or on our behalf. Although we believe our estimates and assumptions to be reasonable, they are inherently uncertain and involve a number of risks and uncertainties that are beyond our control. Our assumptions about future events may prove to be inaccurate. We caution you that the forward-looking statements contained in this Annual Report are not guarantees of future performance, and we cannot assure you that those statements will be realized or the forward-looking events and circumstances will occur. All forward-looking statements speak only as of the respective dates thereof.

We do not intend to publicly update or revise any forward-looking statements as a result of new information, future events or otherwise, except as required by law. These cautionary statements qualify all forward-looking statements attributable to us or persons acting on our behalf.

PART I

ITEM 1. BUSINESS

Company Overview

We are an independent energy company engaged in the exploitation, exploration, development and acquisition of crude oil and natural gas properties. We have historically focused our operations in the onshore U.S. Gulf Coast, Texas and Colorado regions, which are generally characterized by high rates of return in known, prolific producing trends. We have shifted our strategic focus to include longer reserve life resource plays in Southeast Texas (the Woodbine oil plays), South Texas (the Eagle Ford Shale oil play and crude oil play in the Buda formation). We believe these plays provide significant long-term growth potential from multiple formations. Additionally, we have producing properties in the Denver Julesburg Basin ("*DJ Basin*") in Weld and Adams counties in Colorado, which we believe are prospective in the Niobrara Shale oil play. Until we see improvement in natural gas prices, we will focus our drilling activity predominantly on further developing our oil and liquids-rich assets.

We intend to grow reserves and production by developing our existing producing property base including, developing our oil/liquids resource potential in Southeast and South Texas, and by pursuing opportunistic acquisitions in areas where we have current operations and specific operating expertise. In 2012, we successfully transitioned from a predominantly natural gas weighted production profile to a current production profile of approximately 50 percent crude oil and natural gas liquids. We have developed a significant inventory of high quality drilling opportunities on our existing property base that should provide the opportunity for multiyear reserve growth. In 2013, we will continue to focus on our inventory of crude oil and liquids-rich projects in the Woodbine formation with a continuous rig program planned for 2013. We also currently plan to drill one or more test wells in the crude oil play in the Buda formation in Zavala/Dimmit counties in South Texas. We will continue to monitor increasing industry activity in the James Lime play in East Texas and the oil weighted Niobrara Shale in the DJ Basin of Colorado to determine the future potential and strategy for optimizing value in each play prior to expending drilling capital. The results of drilling activity near our acreage will influence our strategy and activity level in these plays; and given success by nearby operators, we may adjust our capital budget to capitalize on opportunities on our acreage positions in these plays.

As of December 31, 2012, our proved reserves, as estimated by Netherland, Sewell & Associates, Inc. ("*NSAI*"), our independent petroleum engineering firm, in accordance with reserve reporting guidelines mandated by the Securities and Exchange Commission ("*SEC*"), were 117.0 Bcfe, consisting of 61.9 Bcf of natural gas and 9.2 MMBbl of crude oil, condensate and natural gas liquids, with a PV-10 of $340.1 million, and a Standardized Measure of Discounted Future Net Cash Flows ("*Standardized Measure*") of $296.4 million. As of December 31, 2012, 53% of our proved reserves were natural gas, 54% were proved developed and 90% were attributed to wells and properties operated by us. Year-end PV-10 is a non-GAAP financial measure. A reconciliation of our Standardized Measure to PV-10 is provided under "Item 2. Properties - Proved Reserves".

The following summary table sets forth certain information with respect to our proved reserves as of December 31, 2012, as estimated by NSAI, and net average daily production and net acreage for the twelve months ended December 31, 2012:

Region	Estimated Proved Reserves (MMcfe)	% Crude Oil	% Natural Gas	% Natural Gas Liquids	% Proved Developed	Average Daily Production (Mcfe/d)	Net acreage
Southeast Texas	50,908	45%	39%	16%	51%	18,909	26,569
South Texas	55,809	21%	64%	15%	57%	15,337	50,972
East Texas	3,964	12%	70%	18%	52%	3,348	4,793
Colorado and Other	6,368	30%	56%	14%	56%	1,001	12,290
Total	117,049	32%	53%	15%	54%	38,595	94,624

Areas of geographic focus as of December 31, 2012 are shown on the map below:

Our areas of primary focus consist of:

- *Southeast Texas*. At December 31, 2012, our Southeast Texas region included approximately 44,000 gross (26,600 net) acres, proven reserves of 50.9 Bcfe, and 72 gross (38.3 net) producing wells. We have actively developed this area since 2008, primarily focusing on the Yegua and Cook Mountain sands in Liberty County until 2012. In 2012, we shifted our focus to the horizontal development of the Woodbine oil potential in Madison and Grimes counties, where there has recently been significant industry activity pursuing the Woodbine and Eagle Ford Shale oil plays near our leasehold positions. We will continue our focus on further developing our inventory of crude oil and liquids-rich projects in the Woodbine formation with a continuous rig program planned for 2013. We currently have approximately 18,900 net acres and an inventory of approximately 498 potential drilling locations in Madison and Grimes counties, which includes our Woodbine, Eagle Ford Shale and Georgetown formations acreage. Drilling locations are based on 160 acre well spacing.

- *South Texas*. At December 31, 2012, our South Texas region included approximately 97,800 gross (51,000 net) acres, proven reserves of 55.8 Bcfe, and 272 gross (145.7 net) producing wells. Approximately 18,500 gross (8,600 net) acres are targeting the Eagle Ford Shale liquids play, over 90% of which is held by production. We began development of the Eagle Ford Shale in Bee County in 2010 and in Karnes and Zavala/Dimmit counties in 2011. In 2012, we successfully drilled 5 gross (3.4 net) producing wells targeting the Eagle Ford Shale. We currently plan to drill one or more test wells in the crude oil play in the Buda formation in Zavala/Dimmit counties in South Texas in 2013. Our estimated net proven Eagle Ford Shale reserves in this area of 13.6 Bcfe were comprised of 76% liquids with 14 gross (7.5 net) producing wells as of December 31, 2012.

  The remaining 79,300 gross (42,400 net) acres in South Texas are located in our conventional fields that produce primarily from the Wilcox, Frio, and Vicksburg sands. Our estimated net proved conventional reserves in this area of 42.3 Bcfe were comprised of 77% gas with 258 gross (138.2 net) producing wells as of December 31, 2012.

- *East Texas.* At December 31, 2012, our East Texas region included approximately 7,500 gross (4,800 net) acres, proven reserves of 4.0 Bcfe comprised of 70% gas, and 8 gross (4.0 net) producing wells. Reflected as a negative revision to proved reserves in the December 31, 2012 reserve report were 91.7 Bcfe of reserves we still own but that were revised downward from proven reserves due to the low natural gas price environment. We actively developed the Haynesville and Mid-Bossier Shales in this area in 2009 through

2011 during a more favorable natural gas price environment. We will continue to monitor the drilling success by larger industry players as well as a midstream solution for processing liquids-rich gas from the James Lime formation in this area. Approximately 85% of our acreage in East Texas was held by production with the majority of the remaining leases expiring in 2013. Other than the aforementioned test wells, we have no plans to drill in the area in 2013 due to a challenging natural gas price environment.

We also own interests in the following areas:

- *Colorado and Other.* This region includes approximately 19,900 gross (12,300 net) acres in the DJ Basin in Colorado (mostly in Adams and Weld counties), small non-operating working interests in the Fenton field area of Calcasieu Parish, Louisiana and a minor crude oil property in Mississippi. There has been increasing activity since 2011 in the area of our Colorado acreage in pursuit of the Niobrara Shale oil formation. Substantially all of our 10,000 net acres in the Niobrara Shale are held by production and we plan to monitor the 2013 industry activity and results of our peers in the Niobrara Shale to develop our strategy for maximizing the value of our position in the area.

We intend to continue to evaluate potential acquisition opportunities in our core areas, to expand our presence in our Southeast and South Texas resource plays, to exploit our oil and liquids-rich positions, and to continue to develop exploitation opportunities on our conventional properties where commodity price-justified. Acquisition efforts will typically be focused on areas in which we can leverage our geographic and geological expertise to exploit identified drilling opportunities, and where we can develop an inventory of additional drilling prospects that we believe will enable us to grow production and add reserves.

Capital expenditures for 2012 were $79.3 million, of which $63.5 million was used to drill 12 gross (7.9 net) wells and to sidetrack one (0.6 net) well with a combined success rate of 100%. The remaining $15.8 million was used to build facilities, acquire and extend leases, and complete wells drilled in prior years. Our 2013 capital budget is currently forecasted to be approximately $58.7 million, exclusive of acquisitions, if any.

Offices

We currently lease and sublease, through January 31, 2019, corporate office space located at 717 Texas Avenue in downtown Houston, Texas. Rent, including parking related to this office space for the twelve months ended December 31, 2012 was approximately $2.4 million. Effective January 1, 2013, we subleased of this space to a third party for a total rental of approximately $85,000 per month from January 1, 2013 through January 31, 2014.

Strategy

The key elements of our business strategy are:

- *Enhance our portfolio by allocating capital to our oil and liquids-rich opportunities.* Beginning in 2011, we allocated substantially all of our capital resources to developing oil and liquids-rich opportunities to transition from a natural gas weighted production profile to a balanced production profile between oil/liquids and natural gas. In 2012, we have successfully transitioned from a 70% natural gas production profile in 2011 to a current production profile of approximately 50 percent crude oil and natural gas liquids. We will continue to pursue a drilling program that is designed to develop our multiple oil and liquids rich opportunities in established, active areas. Due to the challenging natural gas price environment and superior economics from oil production, we allocated our entire 2012 capital budget to oil and liquids-weighted opportunities, and plan to continue this strategy through 2013. We currently plan to develop the oil and natural gas liquids resource potential that we believe exists, from numerous formations, on our Madison and Grimes counties' acreage in Southeast Texas and our Zavala/Dimmit counties' acreage in South Texas. If warranted by market conditions, success in these areas and capital availability, we may further accelerate our drilling program in one or both areas. We currently do not plan to further develop our acreage position in the East Texas Haynesville/Mid-Bossier natural gas plays until the outlook for natural gas prices improves significantly.

- *Pursue the development of the Woodbine horizontal oil redevelopment play in Madison and Grimes counties in Southeast Texas*. We have approximately 26,900 gross (18,900 net) acres in Madison and Grimes counties from which we have historically focused primarily on maximizing existing production from conventional wells. During 2012, we completed 7 gross (4.5 net) wells on our acreage, targeting the Woodbine. We plan to have a rig active in Madison and Grimes counties for all of 2013. Based on those results, we believe that large portions of our acreage position in the area may be prospective for horizontal redevelopment of the Woodbine, Eagle Ford, Georgetown, Lewisville and other formations.

- *Develop South Texas.* In 2012, we drilled 4 gross (2.9 net) wells in our Karnes and Zavala County areas, targeting the Eagle Ford Shale oil window and one gross (0.5 net) well in the Eagle Ford Shale gas/condensate window in Dimmit County. We currently plan to drill one or more test wells in the crude oil play in the Buda formation in Zavala/Dimmit counties in 2013. If availability of capital resources and nearby success warrant it, we may also resume development of our Eagle Ford Shale play.

- *East Texas resource play.* We believe that the further exploitation of our significant unproven resource potential in the Haynesville Shale, Mid-Bossier and James Lime formations, existing on our approximate 7,500 gross (4,800 net) acreage position in East Texas will provide long-term natural gas reserve and production growth in the future. Our interests in this area included 91.7 Bcfe of proved reserves as of December 31, 2012 that were declassified as proved in 2012 after becoming uneconomical due to the low natural gas price environment. We do not anticipate devoting significant drilling capital to this gas-oriented area until we see an improvement in the natural gas price environment and outlook as well as development of a midstream solution for processing liquids-rich James Lime gas. As of December 31, 2012, we had 8 gross (4.0 net) producing gas wells in this area.

- *Colorado Niobrara Shale.* Our activities in Colorado have historically been limited to the production of small amounts of oil and gas from the DJ Basin 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 may provide attractive return possibilities. We believe that the Niobrara Shale is prospective on at least part of our acreage. We plan to limit our activity in 2013 to monitoring the increased activity by larger industry players in the Niobrara Shale. We will evaluate their results to develop a strategy for maximizing the value of our position.

- *Exploit our existing producing conventional property base to generate cash flows.* We believe our multi-year drilling inventory of exploitation opportunities on our existing conventional producing properties provides us with a solid, dependable platform for future reserve and production growth. We own 3D seismic data that covers substantially all of our Liberty County acreage in South Texas, giving us a higher degree of confidence in the potential in this area. Due to our focus on our resource plays, activity on our conventional asset base in 2012 was limited to production enhancing workover activity. As a result of our desire to more extensively develop our positions in the Woodbine and Eagle Ford Shale plays, we have not currently allocated any additional drilling capital to further develop this area in 2013. We do plan to continue to allocate limited capital resources to our existing property base for production enhancing workover activity in 2013

- *Pursue accretive, opportunistic acquisitions that meet our strategic and financial objectives.* We intend to continue evaluating opportunistic acquisitions of crude oil and natural gas 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 utilize commodity price hedge instruments to minimize exposure to declining prices on our crude oil, natural gas and natural gas liquids production. We use a series of swaps and costless collars to accomplish our commodity hedging strategy. As of March 2013, we have 7.9 Bcfe of equivalent production hedged between January 1, 2013 and December 31, 2014. For 2013 production we have 0.3 MBbl of crude oil hedges at an average Brent floor price of $107.44/Bbl, 0.2 MBbl of crude oil hedges at an average WTI floor price of $101.25/Bbl and 3.5 Bcf of natural gas hedges at an average floor price of $3.40/MMBtu. For 2014 production, we have 0.1 MBbl of crude oil hedges at an average Brent floor price of $102.10/Bbl and 1.0 Bcf of natural gas hedges at an average floor price of $3.63/MMBtu.

Our Employees

On March 1, 2013, we had 69 full time employees, of which 20 were field personnel. We have been able to attract and retain a talented team of industry professionals 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 of our existing asset base, as well as the continuing identification and development of new growth opportunities. None of our employees are covered by collective bargaining agreements. We believe our relationship with our employees is good.

Available Information

We file annual, quarterly and other reports and other information with the SEC under the Securities Exchange Act of 1934, as amended (the "*Exchange Act*"). You may read and copy any reports, statements or other information filed by us at the SEC's public reference room at 100 F Street, N.E., Washington, D.C. 20549. Please call the SEC at 1-800-SEC-0330 for further information on the public reference room. Our filings with the SEC are also available to the public from commercial document retrieval services and at the SEC's web site at http://www.sec.gov.

We make available free of charge on our internet website at www.crimsonexploration.com our annual reports on Form 10-K, our quarterly reports on Form 10-Q, our current reports on Form 8-K and any amendments to those reports, as soon as reasonably practicable after we electronically file such material with, or furnish it to, the SEC. Information contained on our website is not incorporated by reference into this Form 10-K and you should not consider such information as part of this report or other information regarding issuers that file electronically with the SEC.

Seasonal Nature of Business

The demand for oil and natural gas fluctuates depending on the time of year. Seasonal anomalies such as mild winters or hot summers sometimes lessen this fluctuation. In addition, pipelines, utilities, local distribution companies, and industrial end users utilize oil and natural gas storage facilities and purchase some of their anticipated winter requirements during the summer. This can also lessen seasonal demand.

Government Regulation and Industry Matters

Federal and State Regulatory Requirements

We are a public company subject to the rules and regulations of the 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 crude oil, natural gas and natural gas liquids production depends upon numerous factors beyond our control. These factors include regulation of crude oil, natural gas, 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 crude oil, natural gas 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 crude oil, natural gas, and natural gas liquids, protect rights to produce crude oil, natural gas and natural gas liquids between owners in a common reservoir, control the amount of crude oil, natural gas 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 U.S. 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 Crude oil, Natural gas 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 crude oil, natural gas 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 (the "*NGA*"), the Federal Energy Regulatory Commission (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 (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 (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 (the "*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 (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 (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 and Occupational Health and Safety Matters

Our crude oil and natural gas exploration, development and production operations are subject to stringent federal, regional, state and local laws and regulations governing occupational health and safety aspects of our operations, the discharge of materials into the environment, or otherwise relating to environmental protection. Numerous governmental authorities, including the U.S. Environmental Protection Agency (the "*EPA*") and analogous state agencies, have the power to enforce compliance with these laws and regulations and the permits issued under them, often requiring difficult and costly actions. These laws and regulations may require the acquisition of a permit to conduct drilling and other regulated activities, restrict the types, quantities and concentration of various substances that may 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; impose specific health and safety criteria addressing worker protection; and impose substantial liabilities for pollution resulting from production and drilling operations. Failure to comply with these laws and regulations may result in the assessment of administrative, civil and criminal penalties, the imposition of remedial obligations, and the issuance of orders enjoining some or all of our operations in affected areas. 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 in the future, resulting in increased costs of doing business and consequently affecting profitability. To the extent laws are enacted or other governmental action is taken that results in more stringent and costly well drilling, construction, completion or water management activities, waste handling, storage, transport, disposal or remediation requirements, our business and prospects could be materially and adversely affected.

The Comprehensive Environmental Response, Compensation and Liability Act, as amended, 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 also generate wastes that are subject to the federal Resource Conservation and Recovery Act, as amended (the *"RCRA"*), and comparable state statutes. The RCRA imposes strict requirements on the generation, storage, treatment, transportation and disposal of nonhazardous and hazardous wastes, and the EPA and various state agencies stringently enforce the approved methods of management and disposal of these wastes. While the RCRA currently exempts certain drilling fluids, produced waters, and other wastes associated with exploration, development and production of crude oil and natural gas from regulation as hazardous wastes, we can provide no assurance that this exemption will be preserved in the future. Repeal or modification of this exclusion or similar exemptions under state law could increase the amount of hazardous waste we are required to manage and dispose of and could cause us to incur increased operating costs, which could have a significant impact on us as well as the natural gas and oil industry in general. In any event, these excluded wastes are subject to regulation as nonhazardous wastes.

We currently own, lease or operate 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 petroleum hydrocarbons or 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.

The Clean Air Act, as amended (the "*CAA*"), and comparable state laws and regulations restrict the emission of air pollutants from many sources and also impose various monitoring and reporting requirements. These laws and regulations may require us to obtain pre-approval for the construction or modification of certain projects or facilities expected to produce or significantly increase air emissions, obtain and strictly comply with stringent air permit requirements or utilize specific equipment or technologies to control emissions. Obtaining permits has the potential to delay the development of crude oil and natural gas projects. Over the next several years, we may be required to incur certain capital expenditures for air pollution control equipment or other air emissions-related issues. For example, on August 16, 2012, the EPA published final rules under the CAA that subject oil and natural gas production, processing, transmission and storage operations to regulation under the New Source Performance Standards ("*NSPS*") and National Emission Standards for Hazardous Air Pollutants ("*NESHAP*") programs. With regards to production activities, these final rules require, among other things, the reduction of volatile organic compound emissions from three subcategories of fractured and refractured gas wells for which well completion operations are conducted: wildcat (exploratory) and delineation gas wells; low reservoir pressure non-wildcat and non-delineation gas wells; and all "other" fractured and refractured gas wells. All three subcategories of wells must route flow back emissions to a gathering line or be captured and combusted using a combustion device such as a flare after October 15, 2012. However, the "other" wells must use reduced emission completions, also known as "green completions," with or without combustion devices, after January 1, 2015. These regulations also establish specific new requirements regarding emissions from production-related wet seal and reciprocating compressors, effective October 15, 2012 and from pneumatic controllers and storage vessels, effective October 15, 2013. We are currently reviewing this new rule and assessing its potential impacts on our operations. Compliance with these requirements could increase our costs of development and production, which costs could be significant.

Based on findings made by the EPA in December 2009 that emissions of carbon dioxide, methane and other greenhouse gases ("*GHGs*") present an endangerment to public health and the environment, the EPA adopted regulations under existing provisions of the CAA that, among other things, establish Prevention of Significant Deterioration ("*PSD*") construction and Title V operating permit reviews for certain large stationary sources that are potential major sources of GHG emissions. Facilities required to obtain PSD permits for their GHG emissions also will be required to meet "best available control technology" standards that will be established by the states or, in some cases, by the EPA on a case-by-case basis. These EPA rulemakings could adversely affect our operations and restrict or delay or ability to obtain air permits for new or modified sources. In addition, the EPA has adopted rules requiring the monitoring and reporting of GHG emissions from specified sources in the United States on an annual basis, which include the majority of our operations. We are monitoring GHG emissions from our operations in accordance with the GHG emissions reporting rule and believe that our monitoring activities are in substantial compliance with applicable reporting obligations.

While Congress has, from time to time considered legislation to reduce emissions of GHGs, there has not been significant activity in the form of adopted legislation to reduce GHG emissions at the federal level in recent years. In the absence of such federal climate legislation, a number of state and regional efforts have emerged that are aimed at tracking and/or reducing GHG emissions by means of cap and trade programs that typically require major sources of GHG emissions, such as electric power plants, to acquire and surrender emission allowances in return for emitting those GHGs. If Congress undertakes comprehensive tax reform in the coming year, it is possible that such reform may include a carbon tax, which could impose additional direct costs on operations and reduce demand for refined products. Although it is not possible at this time to predict how legislation or new regulations that may be adopted to address GHG emissions would impact our business, any such future federal laws or regulations that impose reporting obligations on us with respect to, or require the elimination of GHG emissions from, our equipment or operations 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 an adverse effect on our assets and operations.

The Federal Water Pollution Control Act, as amended (the "*Clean Water Act*") and analogous state laws impose restrictions and strict controls regarding the discharge of pollutants into state waters and waters of the United States. Any such discharge of pollutants into regulated waters is prohibited except in accordance with the terms of a permit issued by the EPA or the analogous state agency. Spill prevention, control and countermeasure 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. The Clean Water Act also prohibits the discharge of dredge and fill material in regulated waters, including wetlands, unless authorized by permit. Federal and state regulatory agencies can impose administrative, civil and criminal penalties for noncompliance with discharge permits or other requirements of the Clean Water Act and analogous state laws and regulations.

The Oil Pollution Act of 1990, as amended (the "*OPA*"), amends the Clean Water Act and contains numerous requirements relating to the prevention of and response to oil spills into waters of the United States. The OPA applies to vessels, offshore facilities, and onshore facilities, including exploration and production facilities that may affect waters of the United States. Under the OPA, responsible parties including owners and operators of onshore facilities may be held strictly liable for oil cleanup costs and natural resource damages as well as a variety of public and private damages that may result from oil spills. The OPA also requires owners or operators of certain onshore facilities to prepare Facility Response Plans for responding to a worst-case discharge of oil into waters of the United States.

Hydraulic fracturing is an important and common practice that is used to stimulate production of natural gas and/or crude oil from dense subsurface rock formations. The hydraulic fracturing process involves the injection of water, sand and chemical additives under pressure into targeted subsurface formations to stimulate production. We routinely use hydraulic fracturing techniques in many of our completion programs. Hydraulic fracturing typically is regulated by state oil and gas commissions, but the EPA has asserted federal regulatory authority pursuant to the federal Safe Drinking Water Act (the "*SDWA*") over hydraulic fracturing involving the use of diesel fuels and published draft permitting guidance in May 2012 addressing the performance of such activities using diesel fuels. In November 2011, the EPA announced its intent to develop and issue regulations under the Toxic Substances Control Act to require companies to disclose information regarding the chemicals used in hydraulic fracturing and the agency currently plans to issue a Notice of Proposed Rulemaking that would seek public input on the design and scope of such disclosure regulations. In addition, Congress has from time to time considered legislation to provide for federal regulation of hydraulic fracturing under the SDWA and to require disclosure of the chemicals used in the hydraulic fracturing process. At the state level, several states, including Texas, where we operate, have adopted, and other states are considering adopting legal requirements that could impose more stringent permitting, public disclosure, or well construction requirements on hydraulic fracturing activities. Local government may also seek to adopt ordinances within their jurisdictions regulating the time, place and manner of drilling activities in general or hydraulic fracturing activities in particular. We believe that we follow applicable standard industry practices and legal requirements for groundwater protection in our hydraulic fracturing activities. Nonetheless, if new or more stringent federal, state, or local legal restrictions relating to the hydraulic fracturing process are adopted in areas where we operate, we could incur potentially significant added costs to comply with such requirements, experience delays or curtailment in the pursuit of exploration, development, or production activities, and perhaps even be precluded from drilling or completing wells.

In addition, certain governmental reviews have been conducted or are underway that focus on environmental aspects of hydraulic fracturing practices. The White House Council on Environmental Quality is coordinating an administration-wide review of hydraulic fracturing practices. The EPA has commenced a study of the potential environmental effects of hydraulic fracturing on drinking water and groundwater, with a first progress report outlining work currently underway by the agency released on December 21, 2012 and a final report drawing conclusions about the potential impacts of hydraulic fracturing on drinking water resources expected to be available for public comment and peer review by 2014. Moreover, the EPA is developing effluent limitations for the treatment and discharge of wastewater resulting from hydraulic fracturing activities and plans to propose these standards by 2014. Other governmental agencies, including the U.S. Department of Energy and the U.S. Department of the Interior have evaluated or, are evaluating various other aspects of hydraulic fracturing. These ongoing or proposed studies, depending on their degree of pursuit and any meaningful results obtained, could spur initiatives to further regulate hydraulic fracturing under the SWDA or other regulatory mechanisms.

To our knowledge, there have been no citations, suits, or contamination of potable drinking water arising from our hydraulic fracturing operations. We do not have insurance policies in effect that are intended to provide coverage for losses solely related to hydraulic fracturing operations; however, we believe our general liability and excess liability insurance policies would cover third-party pollution claims in accordance with, and subject to the terms of such policies.

Oil and natural gas exploration, development and production activities on federal lands, including Indian lands and lands administered by the federal *Bureau* of Land Management ("*BLM*"), are subject to the National Environmental Policy Act, as amended ("*NEPA*"). NEPA requires federal agencies, including the BLM, to evaluate major agency actions having the potential to significantly impact the environment. In the course of such evaluations, an agency will prepare an Environmental Assessment that assesses the potential direct, indirect and cumulative impacts of a proposed project and, if necessary, will prepare a more detailed Environmental Impact Statement that may be made available for public review and comment. Currently, we have minimal exploration and production activities on federal lands. However, for those current activities as well as for future or proposed exploration and development plans on federal lands, governmental permits or authorizations that are subject to the requirements of NEPA are required. This process has the potential to delay, limit or increase the cost of developing oil and natural gas projects.

Environmental laws such as the Endangered Species Act, as amended ("*ESA*"), may impact exploration, development and production activities on public or private lands. The ESA provides broad protection for species of fish, wildlife and plants that are listed as threatened or endangered in the United States, and prohibits taking of endangered species. Federal agencies are required to ensure that any action authorized, funded or carried out by them is not likely to jeopardize the continued existence of listed species or modify their critical habitat. While some of our facilities may be located in areas that are designated as habitat for endangered or threatened species, we believe that we are in substantial compliance with the ESA. If endangered species are located in areas of the underlying properties where we wish to conduct seismic surveys, development activities or abandonment operations, such work could be prohibited or delayed or expensive mitigation may be required. Moreover, as a result of a settlement approved by the U.S. District Court for the District of Columbia in September 2011, the U.S. Fish and Wildlife Service is required to make a determination on listing of more than 250 species as endangered or threatened under the ESA by no later than completion of the agency's 2017 fiscal year. The designation of previously unprotected species as threatened or endangered in areas where underlying property operations are conducted could cause us to incur increased costs arising from species protection measures or could result in limitations on our exploration and production activities that could have an adverse impact on our ability to develop and produce reserves.

We are subject to the requirements of the federal Occupational Safety and Health Act, as amended ("*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, and 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 independent third party 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 senior secured 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 three 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, 2012, 2011 and 2010, our top ten purchasers collectively represented approximately 88%, 83% and 80% of total revenues, respectively. Our four largest purchasers in 2012 accounted for 31% (Sunoco, Inc.), 20% (Valero Marketing & Supply Co.), 14% (DCP Midstream, LP) and 10% (Shell Trading (U.S.) Company) 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 10. "Directors and Executive Officers of the Registrant," which information is incorporated herein by reference.

ITEM 1A. RISK FACTORS

Risks Related to Our Business

Crude oil, natural gas 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 crude oil, natural gas 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 crude oil, natural gas and natural gas liquids prices have a significant impact on the value of our reserves and on our cash flow. Prices for natural gas remained low in 2012 when compared with average prices in prior years. In addition, periods of sustained lower prices may compel us to reduce our capital expenditures and budget for drilling. Prices for crude oil, natural gas and natural gas liquids may fluctuate widely in response to relatively minor changes in the supply of and demand for crude oil, natural gas and natural gas liquids and a variety of additional factors that are beyond our control, such as:

- the domestic and foreign supply of crude oil, natural gas 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 crude oil, natural gas and natural gas liquids prices may not only decrease our revenues on a per share basis, but also may reduce the amount of crude oil, natural gas 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. A reduction in our reserves could have other adverse consequences including a possible downward redetermination of the availability of borrowings under our senior secured revolving credit agreement, which would restrict our liquidity. Additionally, further or continued declines in prices could result in non-cash charges to earnings due to impairment write downs. Any such write-down could have a material adverse effect on our results of operations in the period taken.

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 and South Texas resource plays and the horizontal redevelopment of the Woodbine and other formations in Southeast Texas, are more uncertain than drilling results in areas that are more developed and with longer production history. Since new or emerging plays and new formations have limited production history, we are less able to use past drilling results in those areas to help predict our future drilling results. 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, 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 crude oil, natural gas 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.

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

Our future cash flows are subject to a number of variables, including the level of production from existing wells. Initial production rates in shale plays tend to decline steeply in the first twelve months of production and are not necessarily indicative of sustained production rates. As a result, we generally must locate and develop or acquire new crude oil or natural gas reserves to offset declines in these initial production rates. If we are unable to do so, these declines in initial production rates may result in a decrease in our overall production and revenue over time.

Our development and exploration operations, including on our 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 undeveloped acreage and a decline in our crude oil, natural gas 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 crude oil, natural gas and natural gas liquids reserves. We intend to finance our future capital expenditures primarily with cash flow from operations and borrowings under our senior secured 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 crude oil, natural gas and natural gas liquids we are able to produce from existing wells;
- the prices at which crude oil, natural gas 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 crude oil, natural gas 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 senior secured revolving credit agreement, we may be unable to obtain financing otherwise available under our senior secured 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 crude oil, natural gas and natural gas liquids reserves.

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, 2012, we had $244.1 million outstanding in principal amount, excluding a $4.7 million discount, 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 senior secured 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.

In addition, our borrowing base on our senior secured revolving credit agreement could be reduced by our lenders and limit our availability of future borrowings, or require us to pay back current borrowings in excess of the new borrowing base. If we were required to pay back all or a portion of our debt, even if new financing were then available, it may not be on terms that are acceptable to us. See “—Our development and exploration operations 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 crude oil, natural gas and natural gas liquids reserves.”

Certain U.S. federal income tax deductions currently available with respect to oil and gas exploration and development may be eliminated as a result of future legislation.

Legislation has been proposed in the past that would, if enacted into law, make significant changes to U.S. federal income tax laws, including the elimination of certain key U.S. federal income tax incentives currently available to oil and natural gas exploration and production companies. These proposed changes would include, but are not limited to, (i) the repeal of the percentage depletion allowance for oil and gas properties; (ii) the elimination of current deductions for intangible drilling and development costs; (iii) the elimination of the deduction for certain U.S. production activities; and (iv) an extension of the amortization period for certain geological and geophysical expenditures. It is unclear whether these or similar changes will be enacted and, if enacted, how soon any such changes could become effective. The passage of these or any other similar changes in U.S. Federal income tax laws could eliminate or postpone certain tax deductions that are currently available with respect to oil and natural gas exploration and development, and any such change could negatively impact the value of an investment in our preferred stock or our common stock.

Slower economic recovery in the U.S. and other countries may materially adversely impact our operations results.

The U.S. and other economies are recovering from a global financial crisis and recession which began in 2008. Growth has resumed, but has been modest and at an unsteady rate. There are likely to be significant long-term effects resulting from the financial crisis and recession, including a future global economic growth rate that is slower than what was experienced in the years leading up to the crisis, and more volatility may occur before a sustainable, yet lower, growth rate is achieved.

Global economic growth drives demand for energy from all sources, including crude oil, natural gas 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 of crude oil and natural gas liquids have improved, and we hedged natural gas and crude oil prices on a 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, crude oil, natural gas and natural gas liquids could adversely affect our financial condition and results of operations.

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

We have incurred net losses in four of the last five fiscal years. We cannot assure you that our current level of operating results will continue or improve. Our activities could require additional debt or equity financing. Our future operating results may fluctuate significantly depending upon a number of factors, including industry conditions, prices of crude oil, natural gas 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, 2012, we had federal net operating loss (*"NOL"*) carryforwards of approximately $110.7 million, which are available to reduce our future federal taxable income and related income tax liability. Our federal NOL carryforwards of $110.7 million have a valuation allowance of $38.0 million reducing the amount to $72.7 million. 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 the majority of these NOL carryforwards 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 could be limited if we do not generate sufficient taxable income in future periods and the amount of the related deferred tax asset ultimately realizable could be further 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 NOL carryforwards of approximately $8.8 million, or $3.1 million tax adjusted, due to prior occurrences of an "ownership change", as determined under Section 382 of the Internal Revenue Code, as amended, and have included this amount in our total valuation allowance of $38.0 million. 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 NOL carryforwards 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 NOL carryforwards 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 NOL carryforwards 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 or data could materially reduce the estimated quantities and present value of our reserves.

The process of estimating crude oil, natural gas 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 crude oil, natural gas 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 crude oil, natural gas 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, crude oil, natural gas and natural gas liquids prices, revenues, taxes, development expenditures, operating expenses and quantities of recoverable crude oil, natural gas 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. A decrease in commodity prices can result in significant downward reserve revisions as some reserves are no longer economically producible. Other reserves may reduce PV-10 reserve value despite positive current cash flows, because discounted cash flows might be less than the 10% discount utilized in such measures. In addition, we may adjust estimates of proved reserves to reflect production history, results of exploration and development, prevailing crude oil, natural gas and natural gas liquids prices and other factors, many of which are beyond our control.

Approximately* 46% *of our total estimated proved reserves at December 31, 2012 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 crude oil, natural gas 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 crude oil, natural gas 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 crude oil, natural gas 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, 2012 was based on the 12-month unweighted arithmetic average of the first-day-of-the-month price for the period January through December 2012. For crude oil and natural gas liquids volumes, the average West Texas Intermediate posted price was $91.21 per barrel. For natural gas volumes, the average Henry Hub spot price was $2.76 per MMBtu. The following sensitivity analyses for crude oil and natural gas do not include the volatility reducing effects of our derivative hedging instruments in place at December 31, 2012. If crude oil prices were $1.00 per Bbl lower than the price used, our PV-10 as of December 31, 2012 would have decreased from $340.1 million to $335.4 million. If natural gas prices were $0.10 per Mcf lower than the price used, our PV-10 as of December 31, 2012, would have decreased from $340.1 million to $336.4 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. A reconciliation of our Standardized Measure 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 crude oil, natural gas 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 crude oil, natural gas 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 crude oil, natural gas 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, oil spills, pipeline and tank ruptures, encountering naturally occurring radioactive materials, and discharges of toxic gases, brine, well stimulation and completion fluids, or other pollutants into the surface and subsurface environment;
- 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 or of water used in hydraulic fracturing activities;
- 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 crude oil, natural gas 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 crude oil, natural gas 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 crude oil, natural gas and natural gas liquids properties that have economically recoverable reserves for acceptable prices.

We may incur substantial impairment of proved properties.

If management's estimates of the recoverable proved reserves on a property are revised downward or if oil and/or natural gas prices decline, we may be required to record additional non-cash impairment write-downs in the future, which would result in a negative impact to our financial results. Furthermore, any sustained decline in oil and/or natural gas prices may require us to make further impairments. We review our proved oil and gas properties for impairment on a depletable unit basis when circumstances suggest there is a need for such a review. To determine if a depletable unit is impaired, we compare the carrying value of the depletable unit to the undiscounted future net cash flows by applying management's estimates of future oil and natural gas prices to the estimated future production of oil and gas reserves over the economic life of the property. Future net cash flows are based upon our independent reservoir engineers' estimates of proved reserves. In addition, other factors such as probable and possible reserves are taken into consideration when justified by economic conditions. For each property determined to be impaired, we recognize an impairment loss equal to the difference between the estimated fair value and the carrying value of the property on a depletable unit basis.

Fair value is estimated to be the present value of expected future net cash flows. Any impairment charge incurred is recorded in accumulated depreciation, depletion, and amortization to reduce our recorded basis in the asset. Each part of this calculation is subject to a large degree of judgment, including the determination of the depletable units' estimated reserves, future cash flows and fair value. For the years ended December 31, 2012, 2011 and 2010, we recorded impairments related to proved oil and gas properties of $114.4 million, zero and $0.5 million, respectively.

Management's assumptions used in calculating oil and gas reserves or regarding the future cash flows or fair value of our properties are subject to change in the future. Any change could cause impairment expense to be recorded, impacting our net income or loss and our basis in the related asset. Any change in reserves directly impacts our estimate of future cash flows from the property, as well as the property's fair value. Additionally, as management's views related to future prices change, the change will affect the estimate of future net cash flows and the fair value estimates. Changes in either of these amounts will directly impact the calculation of impairment.

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 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.

A majority of our production, revenue and cash flow from operating activities are derived from assets that are concentrated in a few geographic areas, mostly within the state of Texas, making us vulnerable to risks associated with operating in those few geographic areas.

The majority of our estimated proved reserves at December 31, 2012 and our production during 2012 were associated with our Southeast and South Texas properties. Accordingly, if the level of production from these properties substantially declines or is otherwise subject to a disruption in our operations resulting from operational problems, government intervention (including potential regulation or limitation of the use of high pressure fracture stimulation techniques in these formations) or natural disasters, it could have a material adverse effect on our overall production level and our revenue.

If our access to sales 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 crude oil, natural gas and natural gas liquids transportation arrangements may hinder our access to crude oil, natural gas and natural gas liquids markets or delay our production. The availability of a ready market for our crude oil, natural gas and natural gas liquids production depends on a number of factors, including the demand for and supply of crude oil, natural gas 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 crude oil, natural gas 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 crude oil, natural gas 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 crude oil, natural gas and natural gas liquids reservoirs generally are characterized by declining production rates that vary depending upon reservoir characteristics and other factors. Our future crude oil, natural gas 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 crude oil, natural gas and natural gas liquids increase, or the demand for equipment and services is greater than the supply in certain areas, 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 crude oil, natural gas and natural gas liquids, as well as interest rates, we currently, and may in the future, enter into derivative arrangements for a portion of our crude oil, natural gas and/or natural gas liquids production and our debt that could result in both realized and unrealized hedging losses. We utilize financial instruments to hedge commodity price exposure to declining prices on our crude oil, natural gas and natural gas liquids production. We typically use a combination of puts, swaps and costless collars.

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 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 crude oil, natural gas 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, crude oil, natural gas 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 GHGs could result in increased operating costs and reduced demand for the oil and natural gas we produce.

In December 2009, the EPA determined that emissions of 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 adopted regulations under existing provisions of the CAA establishing PSD construction and Title V operating permit requirements for certain large stationary sources that are potential major sources of GHG emissions. We could become subject to these PSD and Title V permit requirements and be required to install "best available control technology" to limit emissions of GHGs from any new or significantly modified facilities that we seek to construct in the future if such facilities emitted volumes of GHGs in excess of threshold permitting levels. The EPA has also adopted regulations requiring the reporting of GHG emissions from specified large GHG emission sources in the United States on an annual basis, including certain onshore and offshore oil and natural gas production facilities, which may include certain of our operations.

While Congress has from time to time considered adopting legislation to reduce emissions of GHGs, there has not been significant activity in the form of adopted legislation to reduce GHG emissions at the federal level in recent years. As a result, a number of state and regional efforts have emerged that are aimed at tracking and/or reducing GHG emissions by means of cap and trade programs that typically require major sources of GHG emissions, such as electric power plants, to acquire and surrender emission allowances in return for emitting those GHGs. If Congress undertakes comprehensive tax reform in the coming year, it is possible that such reform may include a carbon tax, which could impose additional direct costs on operations and reduce demand for refined products. Although it is not possible at this time to predict how legislation or new regulations that may be adopted to address GHG emissions would impact our business, any such future laws and regulations could require us to incur increased operating costs, such as costs to purchase and operate emissions control systems, to acquire emission allowances or comply with new regulatory or reporting requirements including the imposition of a carbon tax. Any such legislation or regulatory programs could also increase the cost of consuming, and thereby reduce demand for oil and natural gas, which could reduce the demand for the oil and natural gas that we produce. Finally, 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, state and local legislative and regulatory initiatives relating to hydraulic fracturing, as well as governmental reviews of such activities, could result in increased costs, additional operating restrictions or delays, and adversely affect our production.

Hydraulic fracturing is an important and common practice that is used to stimulate production of natural gas and/or oil from dense subsurface rock formations. The hydraulic fracturing process involves the injection of water, sand and chemicals under pressure into targeted subsurface formations to fracture the surrounding rock and stimulate production. We routinely use hydraulic fracturing techniques in many of our drilling and completion programs Hydraulic fracturing typically is regulated by state oil and natural gas commissions, but the EPA has asserted federal regulatory authority under the Federal Safe Drinking Water Act over certain hydraulic fracturing activities involving the use of diesel fuels and published draft permitting guidance in May 2012 addressing the performance of such activities using diesel fuels. Also, in November 2011, the EPA announced its intent to develop and issue regulations under the Toxic Substances Control Act to require companies to disclose information regarding the chemicals used in hydraulic fracturing and the agency currently plans to issue a Notice of Proposed Rulemaking that would seek public input on the design and scope of such disclosure regulations. Moreover, from time to time, Congress has considered adopting legislation intended to provide for federal regulation of hydraulic fracturing and to require disclosure of the chemicals used in the hydraulic fracturing process. In addition to any actions by Congress, certain states have adopted or are considering adopting legal requirements that could impose new or more stringent permitting, public disclosure, and well construction requirements on hydraulic fracturing activities. Local government also may seek to adopt ordinances within their jurisdictions regulating the time, place or manner of drilling activities in general or hydraulic fracturing activities in particular. In the event that new or more stringent federal, state, or local legal restrictions relating to the hydraulic fracturing process are adopted in areas where we currently or in the future plan to operate, we could incur potentially significant added costs to comply with such requirements, experience delays or curtailment in the pursuit of exploration, development, or production activities, and perhaps even be precluded from drilling wells.

In addition, certain governmental reviews are either underway or being proposed that focus on environmental aspects of hydraulic fracturing practices. The White House Council on Environmental Quality is coordinating an administration-wide review of hydraulic fracturing practices. The EPA has commenced a study of the potential environmental effects of hydraulic fracturing on drinking water and groundwater, with a first progress report outlining work currently underway by the agency released on December 21, 2012 and a final report drawing conclusions about the potential impacts of hydraulic fracturing on drinking water resources expected to be available for public comment and peer review by 2014. Moreover, the EPA is developing effluent limitations for the treatment and discharge of wastewater resulting from hydraulic fracturing activities and plans to propose these standards by 2014. Other governmental agencies, including the U.S. Department of Energy and the U.S. Department of the Interior, have evaluated or are evaluating various other aspects of hydraulic fracturing. These studies, depending on their degree of pursuit and any meaningful results obtained, could spur initiatives to further regulate hydraulic fracturing under the federal Safe Drinking Water Act or other regulatory mechanisms.

Our operations are subject to compliance with environmental and occupational health and safety laws and regulations that may expose us to significant costs and liabilities.

Our oil and natural gas exploration and production operations are subject to stringent and comprehensive federal, regional, state and local laws and regulations governing occupational 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, underground injection or other regulated 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 EPA the OSHA 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 well drilling, construction, completion or water management activities, or 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."

The enactment of derivatives legislation 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 Dodd-Frank Wall Street Reform and Consumer Protection Act ("*Dodd-Frank Act*") enacted in 2010, establishes federal oversight and regulation of the over-the-counter derivatives market and entities, such as us, that participate in that market. The Dodd-Frank At requires the Commodities Futures Trading Commission ("*CFTC*") and the SEC to promulgate rules and regulations implementing the Dodd-Frank Act. In its rulemaking under the Dodd-Frank Act, the CFTC issued a final rule on position limits for certain futures and option contracts in the major energy markets and for swaps that are their economic equivalents. Certain bona fide hedging transactions or positions are exempt from these position limits. The position-limits rule was vacated by the U.S. District Court for the District of Colombia in September 2012 and the CFTC recently stated that it will appeal the District Court's decision. The CFTC also finalized other regulations, including critical rulemakings on the definition of "swap," "swap dealer," and "major swap participant." Some regulations, however, remain to be finalized and it is not possible at this time to predict when this will be accomplished. The Dodd-Frank Act and regulations may also require the counterparties to our derivative instruments to spin off some of their derivatives activities to separate entities, which may not be as creditworthy as the current counterparties. The Dodd-Frank Act and 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 Dodd-Frank Act 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. Increased volatility may make us less attractive to certain types of investors. Finally, the Dodd-Frank Act 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 46.1 million shares of our common stock outstanding at December 31, 2012, approximately 15.5 million shares were beneficially held by OCM GW Holdings, LLC (*"Oaktree Holdings"*) and 6.7 million shares were 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 33.7% voting interest in us and ACEC owns or controls outstanding common stock representing, in the aggregate, an approximate 14.5% 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 election of directors, 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 crude oil, natural gas 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, our significant stockholders 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 senior secured 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, 2012, we had approximately 1.7 million options to purchase shares of our common stock outstanding, of which 0.5 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, 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 the authority to issue "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 upon liquidation. 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 ("*Common Stock*"). As of December 31, 2012, there were approximately 46.3 million and 46.1 million shares of Common Stock issued and outstanding, respectively. 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 1B. UNRESOLVED STAFF COMMENTS

None.

ITEM 2. PROPERTIES

As of December 31, 2012, we operated a majority of our producing wells in which we held an average 41% 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, and primarily in Texas. As of December 31, 2012, our properties were located in the following regions: Southeast Texas, South Texas, East 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 and future net revenue as of December 31, 2012, 2011, and 2010 were prepared by NSAI in accordance with the definitions and regulations of the SEC. The scope and results of their procedures are summarized in a report 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 estimates of proved reserves and future net revenue are reviewed by our corporate reservoir engineering department that is independent of the operations department. The corporate reservoir engineering department interacts with geoscience, operating, accounting, and marketing departments to review the integrity, accuracy and timeliness of the data, methods, and assumptions used in the preparation of the reserves estimates. All relevant data is compiled in a computer database application to which only authorized personnel are given access rights. Our Senior Vice President - Engineering is the person primarily responsible for overseeing the preparation of our internal reserve estimates and for reviewing any reserves estimates prepared by an independent petroleum engineering firm. Our Senior Vice President - Engineering has a Bachelor of Science degree in Petroleum Engineering from the University of Texas and over 35 years of industry experience with positions of increasing responsibility. He reports directly to our President and Chief Executive Officer. Reserves are also reviewed internally with senior management and presented to our Board of Directors in summary form on a quarterly basis.

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

	2012	2011	2010
Crude Oil (MBbl)			
Developed	2,343	1,845	1,403
Undeveloped	3,859	1,889	761
Total	6,202	3,734	2,164
Natural Gas (MMcf)			
Developed	39,554	53,024	60,325
Undeveloped	22,330	109,676	75,350
Total	61,884	162,700	135,675
Natural Gas Liquids (MBbl)			
Developed	1,686	1,637	1,898
Undeveloped	1,306	907	1,075
Total	2,992	2,544	2,973
Total MMcfe			
Developed	63,732	73,916	80,130
Undeveloped	53,317	126,453	86,368
Total	117,049	200,369	166,498
Proved developed reserves percentage	54%	37%	48%
PV-10 (in millions) (1)	$ 340.1	$ 266.5	$ 239.7
Standardized Measure (in millions) (2)	$ 296.4	$ 255.3	**$** 226.5
Estimated reserve life (in years)	8.3	12.1	12.9
Prices utilized in estimates (3):			
Crude oil ($/Bbl)	$ 91.21	$ 92.71	$ 75.96
Natural gas ($/MMBtu)	$ 2.76	$ 4.12	$ 4.38
Natural gas liquids ($/Bbl)	$ 46.08	$ 47.84	$ 40.38
Average production cost ($/Mcfe) (4)	$ 1.08	$ 0.80	$ 1.16

(1) PV-10 at year-end is a non-GAAP financial measure. A reconciliation of our Standardized Measure of Discounted Net Cash Flows to PV-10 is provided under "—Non-GAAP Financial Measures and Reconciliations."

(2) The Standardized Measure of Discounted Net Cash Flows represents the present value of estimated future cash inflows from proved natural gas and crude oil reserves, less future development and production costs, and income tax expenses, discounted at 10% per annum to reflect timing of future cash flows and using the same pricing assumptions as were used to calculate PV-10. Standardized Measure differs from PV-10 because Standardized Measure includes the effect of future income taxes.

(3) Under SEC rules, prices used in determining our proved reserves 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). 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. All prices, under both sets of rules, are adjusted for quality, energy content, transportation fees and regional price differentials in determining proved reserves.

(4) Average production cost includes oil and gas operating and workover expense and excludes ad valorem and severance taxes.

PV-10

PV-10 at year-end is a non-GAAP financial measure and represents the present value, discounted at 10% per year, of estimated future cash inflows from proved natural gas and crude oil reserves, less future development and production costs using pricing assumptions in effect at the end of the period. PV-10 differs from Standardized Measure of Discounted Net Cash Flows because it does not include the effects of income taxes on future net revenues. Neither PV-10 nor Standardized Measure of Discounted Net Cash Flows 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 to PV-10:

	December 31,		
	2012	**2011**	**2010**
		(in millions)	
Standardized measure of discounted future net cash flows	$ 296.4	$ 255.3	$ 226.5
Present value of future income taxes discounted at 10%	43.7	11.2	13.2
PV-10	$ 340.1	$ 266.5	$ 239.7

The following table reflects our estimated proved reserves by category as of December 31, 2012.

	Crude Oil (MBbl)	Natural Gas (MMcf)	Natural Gas Liquids (MBbl)	Total (MMcfe)	% of Total Proved	PV-10
						(in millions)
Proved developed producing	2,107	27,658	1,138	47,128	40%	$ 168.8
Proved developed non-producing	236	11,896	548	16,604	14%	29.1
Proved undeveloped	3,859	22,330	1,306	53,317	46%	142.2
Total	6,202	61,884	2,992	117,049	100%	$ 340.1

Our estimated net proved reserves as of December 31, 2012, were approximately 32% crude oil and condensate, 53% natural gas and 15% natural gas liquids.

Our average proved reserves-to-production ratio, or average reserve life, is approximately 8.3 years based on our proved reserves as of December 31, 2012 and production for the twelve months ended December 31, 2012. During 2012, 12 gross (7.9 net) operated and non-operated wells were drilled, all of which were successful.

Proved Developed Reserves

Total proved developed reserves decreased from 73.9 Bcfe at December 31, 2011 to 63.7 Bcfe at December 31, 2012. The change in proved developed reserves was attributable to 3.6 Bcfe of new crude oil, natural gas and natural gas liquids reserves added from drilling, 0.3 Bcfe in positive performance revisions, offset by 14.1 Bcfe related to 2012 production.

Proved Undeveloped Reserves

Total proved undeveloped reserves decreased to 53.3 Bcfe at December 31, 2012 compared to 126.5 Bcfe at December 31, 2011. The decrease was attributable to 3.5 Bcfe drilled and converted to proved developed reserves during 2012, 0.8 Bcfe reduction in reserves that we do not plan to develop within five years and 91.7 Bcfe in negative revisions related to lower natural gas prices resulting in a number of uneconomic natural gas well locations being removed from proved undeveloped status, partially offset by 22.8 Bcfe in new additions as a result of the success of the 2012 drilling program. The 0.8 Bcfe reduction in proved undeveloped reserves relates primarily to conventional natural gas reserves in South Texas that we do not plan to drill within five years due to the current low natural gas price environment and outlook, and our strategic change in focus to oil-weighted resource plays.

All of our current proved undeveloped locations represented in our year-end reserve report are expected to be drilled before the end of five years from the date of originally booking the reserves as proved undeveloped. Development costs related to proved undeveloped reserves are projected to be $149.2 million for the next five years. Our financial resources are expected to be sufficient to drill all of the remaining 53.3 Bcfe of proved undeveloped reserves within the five year period.

Significant Properties

Summary proved reserve information for our properties as of December 31, 2012, by region, is provided below.

	Proved Reserves				PV-10 (1) (2)
Regions	Crude Oil	Natural Gas	Natural Gas Liquids	Total	Amount
	(MBbl)	(MMcf)	(MBbl)	(MMcfe)	(in millions)
Southeast Texas	3,843	19,824	1,337	50,908	$ 201.9
South Texas	1,968	35,707	1,382	55,809	126.4
East Texas	76	2,794	119	3,964	1.7
Colorado & Other	315	3,559	154	6,368	10.1
Total	6,202	61,884	2,992	117,049	$ 340.1

(1) Under SEC rules, prices used in determining our proved reserves 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). 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. All prices, using SEC rules, are adjusted for quality, energy content, transportation fees and regional price differentials in determining proved reserves.

(2) Standardized Measure for total proved reserves at December 31, 2012 was $296.4 million.

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, 2012:

	Crude Oil		Natural Gas	
	Gross Wells	Net Wells	Gross Wells	Net Wells
Southeast Texas	16	8.6	56	29.7
South Texas	25	12.5	247	133.1
East Texas	—	—	8	3.9
Colorado & Other	6	2.5	50	20.8
Total	47	23.6	361	187.5

In addition, as of December 31, 2012, we had 158 inactive wells and 26 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 crude oil, natural gas 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, 2012.

	Developed		Undeveloped	
	Gross Acres	Net Acres	Gross Acres	Net Acres
Southeast Texas	24,263	13,837	19,704	12,732
South Texas	84,187	42,930	13,642	8,043
East Texas	5,674	3,681	1,794	1,112
Colorado & Other	10,314	5,598	9,560	6,692
Total	124,438	66,046	44,700	28,579

If production is not established or if we take no action to extend the terms of our leases, undeveloped acreage will expire over the next three years as follows:

	Year ending December 31,					
	2013		2014		2015	
	Gross Acres	Net Acres	Gross Acres	Net Acres	Gross Acres	Net Acres
Southeast Texas	2,368	1,419	7,238	5,054	1,757	914
South Texas	1,687	670	2,698	1,051	—	—
East Texas	1,270	634	482	435	—	—
Colorado & Other	—	—	—	—	—	—
Total	5,325	2,723	10,418	6,540	1,757	914

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, 2012.

	2012	**2011**	**2010**
Gross Wells			
Development	10	11	9
Exploratory	2	2	1
Dry	—	1	1
Total	12	14	11
Net Wells			
Development	6.57	6.32	3.91
Exploratory	1.34	1.03	—
Dry	—	0.55	0.62
Total	7.91	7.90	4.53

At December 31, 2012, we had no wells in progress. The dry (unsuccessful) wells drilled in 2011 and 2010 were development wells.

Property Dispositions

The following table shows oil and gas property dispositions for the past three years ended December 31, 2012:

	2012	2011	2010
Oil and gas properties	$ —	$ —	$ 2,601,997
Accumulated DD&A	—	—	(1,406,066)
Oil and gas properties, net	$ —	$ —	$ 1,195,931

The dispositions resulted in net losses of zero, zero and $1.1 million for the years ended December 31, 2012, 2011 and 2010, respectively.

ITEM 3. LEGAL PROCEEDINGS

From time to time, we are involved in legal proceedings relating to claims associated with our properties, operations or business or arising from disputes with vendors in the normal course of business, including the matters discussed below.

Mineral interest owners in East Texas filed two causes of action against us on May 26, 2009 and August 26, 2009, respectively, in the District Court for San Augustine County in Texas alleging breach of contract for not paying lease bonuses on certain prospective oil and gas leases that were pursued by our leasing agent but never taken by Crimson. These cases were settled in January 2013 for an immaterial amount.

The holders of oil and gas leases in South Louisiana filed suit against Crimson and several co-defendants in June 2009 in the 31st Judicial District Court situated in Jefferson Davis Parish, Louisiana alleging failure to act as a reasonably prudent operator, failure to explore, waste, breach of contract, etc. in connection with two wells located in Jefferson Davis Parish. Many of the alleged improprieties occurred prior to our ownership of an interest in the wells at issue, although we may have assumed liability otherwise attributable to our predecessors-in-interest through the acquisition documents relating to the acquisition of our interest in these wells. The damages most recently alleged by the plaintiffs are approximately $13.4 million. We and our co-defendants are vigorously defending this lawsuit and believe that we have meritorious defenses. We do not believe this suit 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, Crimson, several predecessor operators and several product purchasers were named in a lawsuit filed in the District Court for Lavaca County in Texas by an entity alleging that it owns a working interest in a productive formation that has not been recognized by us or 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 trial court recently granted the plaintiffs motion for partial summary judgment as to liability. We are reviewing our potential exposure associated with this case and estimate that the maximum amount of damages that could be asserted by the plaintiffs is $4.9 million, exclusive of interest and legal fees which may be recoverable by the plaintiff if it ultimately prevails in this case. We are vigorously defending this lawsuit, believe that we have meritorious defenses and intend to appeal the aforementioned decision. 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.

In September 2012, we were named as defendant in a lawsuit filed in district court for Harris County in Texas involving a title dispute over a 1/16th mineral interest in the producing intervals of certain wells operated by us in the Catherine Henderson "A" Unit in Liberty County in Texas. The plaintiff has alleged that, based on its interpretation of a series of 1972 deeds, it owns a 1/16th unleased mineral interest in the producing intervals of these wells on which it has not been paid (this claimed interest is in addition to a 1/16th unleased mineral interest on which it has been paid). We have made royalty payments with respect to the disputed interest in reliance, in part, upon leases obtained from successors to the grantors under the aforementioned deeds, who claim to have retained the disputed mineral interests thereunder, and we have intervened in a lawsuit regarding the disputed interest filed by these successors in the District Court for Liberty County. The plaintiff alleges damages in excess of $6.0 million, which is based on prior payments received on its undisputed 1/16th mineral interest. This case remains in its early stages and we are assessing the plaintiff's claims and issues associated therewith, but we intend to vigorously defend this lawsuit. We believe if this matter were to be determined adversely, amounts owed to the plaintiff could be partially offset by recoupment rights we may have against other working interest and/or royalty interest owners in the unit. We do not believe this suit 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.

While many of these matters involve inherent uncertainty and we are unable at the date of this report to estimate an amount of possible loss with respect to certain of these matters, we believe that the amount of the liability, if any, ultimately incurred with respect to these proceedings or claims will not have a material adverse effect on our consolidated financial position as a whole or on our liquidity, capital resources or future annual results of operations.

ITEM 4. MINE SAFETY DISCLOSURES

Not applicable.

PART II

ITEM 5. MARKET FOR OUR COMMON STOCK

Our Common Stock is currently trading on the NASDAQ Global Market (“NASDAQ”) under the symbol “CXPO”.

The following table sets forth the range of high and low sales prices per share of our Common Stock as reported by NASDAQ.

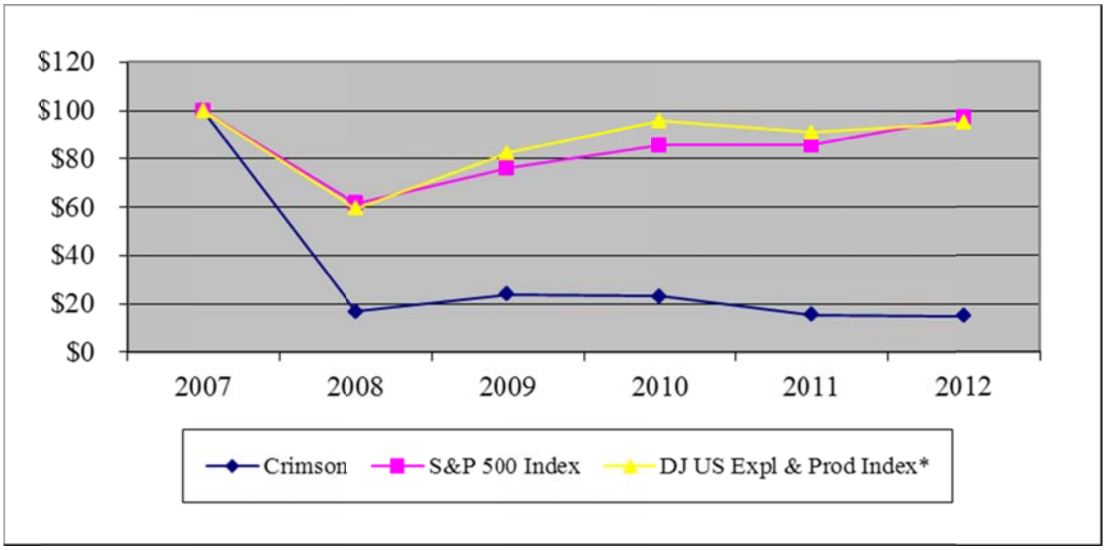
	High	Low
2012		
First Quarter	$ 4.17	$ 2.60
Second Quarter	5.69	3.64
Third Quarter	5.15	3.80
Fourth Quarter	4.46	2.45
2011		
First Quarter	$ 4.73	$ 3.29
Second Quarter	4.27	3.14
Third Quarter	3.84	2.00
Fourth Quarter	3.30	2.02

Between January 1, 2013 and March 1, 2013, our Common Stock traded at prices between $2.68 and $3.42 per share.

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, 2012 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, 2007 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, 2007	$	100.00	$	100.00	$	100.00
December 31, 2008	$	16.85	$	61.51	$	59.37
December 31, 2009	$	23.80	$	75.94	$	82.53
December 31, 2010	$	23.15	$	85.65	$	95.55
December 31, 2011	$	15.54	$	85.65	$	90.81
December 31, 2012	$	14.89	$	97.13	$	94.97

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. As of March 1, 2013, there were approximately 46.3 million shares of Common Stock issued and 46.1 million shares of Common Stock outstanding held by approximately 250 record holders. Approximately 1.7 million shares are in reserve for outstanding stock options under our Amended and Restated 2005 Stock Incentive Plan ("*2005 Plan*") at March 1, 2013. 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. We have not paid any cash dividends on our Common Stock. We do not anticipate paying any cash dividends on our Common Stock in the foreseeable future, as we currently intend to retain all future earnings to fund the development and growth of our business. Our senior secured revolving credit agreement and our second lien credit agreement currently restrict our ability to pay cash dividends on our Common Stock, and we may also enter into credit agreements or other borrowing arrangements in the future that restrict or limit our ability to pay cash dividends on our Common Stock.

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.

Share-Based Compensation

The following table sets forth certain information regarding our equity compensation plans as of December 31, 2012.

Plan Category	Number of securities to be issued upon exercise of outstanding options, warrants and rights (A)	Weighted-average exercise price of outstanding options, warrants and rights (B)	Number of securities remaining available for future issuance under equity compensation plans (excluding securities reflected in Column (A) (C)
Equity compensation plans approved by security holders	1,675,419	$ 4.36	1,147,380
Total	1,675,419	$ 4.36	1,147,380

Our equity compensation plan with outstanding options that has been approved by our stockholders to date is our 2005 Plan.

Our 2005 Plan has been authorized with the issuance of up to approximately 5.8 million shares of Common Stock pursuant to awards under the plan. We also issued 250,000 shares of restricted Common Stock to our executive officers outside of this plan. Approximately 1.7 million (0.5 million vested) stock options and 1.8 million unvested restricted shares were outstanding at December 31, 2012. Option awards outstanding have exercise prices ranging from $2.13 to $5.00 per share. In 2012 and 2011, respectively, 393,127 and 354,051 shares of restricted Common Stock vested, of which 53,826 and 46,215 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, 2012, we had approximately 1.1 million shares of Common Stock available for future grant under the 2005 Plan.

During the first quarter 2013, we issued restricted stock awards for 632,000 shares of Common Stock to employees. As a result, we have 515,380 shares available to be awarded pursuant to the 2005 Plan.

Recent Sales of Unregistered Securities

As shown in the table below, during the years ended December 31, 2012, 2011 and 2010, we issued Common Stock not registered under the Securities Act of 1933 (the "*Act*"), as amended, in transactions we believe are exempt from the registration requirements of the Act 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	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

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, 2012. 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,				
	2012	**2011**	**2010**	**2009**	**2008**
Statement of Operations Data					
Operating revenues [1]	$ 115,904,016	$ 113,636,033	$ 95,932,223	$ 111,802,764	$ 185,680,115
Income (loss) from operations [1][2]	(98,450,589)	2,338,598	(14,345,817)	(457,793)	45,835,055
Net income (loss)	(91,991,355)	(15,845,382)	(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	(91,991,355)	(15,845,382)	(30,844,897)	(38,592,635)	41,969,168
Net income (loss), per share					
Basic	(2.08)	$ (0.35)	$ (0.78)	$ (4.91)	$ 7.81
Diluted	(2.08)	$ (0.35)	$ (0.78)	$ (4.91)	$ 4.46
Weighted average shares outstanding					
Basic	44,147,787	44,788,551	39,397,486	7,861,054	5,371,377
Diluted	44,147,787	44,788,551	39,397,486	7,861,054	10,360,348

(1) Operating overhead and other income of $0.7 million, $0.6 million, $0.6 million and $1.1 million for the years ended December 31, 2011, 2010, 2009 and 2008, respectively, was reclassified to General and administrative expenses ($0.6 million, $0.6 million, $0.6 million and $0.8 million for the years ended December 31, 2011, 2010, 2009 and 2008, respectively) and Other financing costs ($0.1 million, $0.0 million, $0.0 million and $0.3 million for the years ended December 31, 2011, 2010, 2009 and 2008, respectively).

(2) Non-cash equity-based compensation charges were $2.5 million, $1.9 million, $1.8 million, $2.4 million and $5.4 million in 2012, 2011, 2010, 2009 and 2008, respectively.

	Year Ended December 31,				
	2012	2011	2010	2009	2008
Balance Sheet Data					
Current assets	$ 24,824,474	$ 21,072,180	$ 27,562,216	$ 24,710,943	$ 46,347,553
Total assets	368,620,389	436,325,874	412,686,826	424,804,034	511,545,789
Current liabilities	38,685,288	67,086,136	47,370,072	33,486,034	83,989,610
Noncurrent liabilities	250,092,984	199,734,040	181,785,783	208,587,112	305,933,376
Stockholders’ equity	79,842,117	169,505,698	183,530,971	182,730,888	121,622,803

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

We are 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, South Texas and Colorado regions, which are generally characterized by high rates of return in known, prolific producing trends. We have expanded our strategic focus to include longer reserve life resource plays in East Texas and South Texas that we believe provide significant long-term growth potential in multiple formations. We are also focusing on further developing our oil/liquid weighted assets.

We intend to grow reserves and production by developing our existing producing property base, pursuing our Southeast Texas Woodbine horizontal oil redevelopment, 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 track record of adding reserves through successful drilling. Since January 2008 and through December 2012, we have drilled 68 gross (35.0 net) wells with an overall success rate of 94%. At December 31, 2012, we had no wells in progress.

As of December 31, 2012, our proved reserves, as estimated by NSAI in accordance with reserve reporting guidelines mandated by the SEC, were 117.0 Bcfe, consisting of 61.9 Bcf of natural gas and 9.2 MMBbl of crude oil, condensate and natural gas liquids with a PV-10 of $340.1 million. As of December 31, 2012, 53% of our proved reserves were natural gas, 54% were proved developed and 90% were attributed to wells and properties operated by us.

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, 2012 Compared to Year Ended December 31, 2011

Revenues

	Year Ended December 31,			
	2012	**2011**	**Change**	**Percent Change**
Product revenues:		(in millions, except percentages)		
Crude oil sales	$ 78.6	$ 36.8	$ 41.8	113.6%
Natural gas sales	26.5	56.7	(30.2)	-53.3%
Natural gas liquids sales	10.9	20.2	(9.3)	-46.0%
Product revenues	$ 116.0	$ 113.7	$ 2.3	2.0%

Crude Oil, Natural Gas and Natural Gas Liquids Sales. Revenues from the sale of crude oil, natural gas and natural gas liquids, net of the realized effects of our hedging instruments, were $116.0 million in 2012 compared to $113.7 million in 2011. The increase results primarily from a 90% increase in higher value oil production, offset, in part, by declines in natural gas production and lower realized natural gas and natural gas liquids prices.

Production

	Year Ended December 31,			
	2012	2011	Change	Percent Change
Sales volumes:				
Crude oil (Bbl)	753,980	396,760	357,220	90.0%
Natural gas (Mcf)	7,799,301	11,675,602	(3,876,301)	-33.2%
Natural gas liquids (Bbl)	300,435	417,956	(117,521)	-28.1%
Natural gas equivalents (Mcfe)	14,125,791	16,563,898	(2,438,107)	-14.7%

Production was approximately 14.1 Bcfe in 2012 compared to 16.6 Bcfe in 2011. On a daily basis, we produced an average of 38,595 Mcfe per day in 2012 compared to an average of 45,381 Mcfe per day in 2011. Our shift to drilling lower equivalent producing rate, higher value, oil and liquids-rich wells in 2012, which contributed to a corresponding decline in natural gas production, resulted in the decrease in equivalent production volumes. The 28% decrease in natural gas liquids production resulted primarily from the temporary loss of our Catherine Henderson A-6 well in Liberty County in Texas due to mechanical problems, and to purchaser constraints on natural gas liquids processing in Liberty and Karnes counties in Texas. The Catherine Henderson A-6 was successfully sidetracked, and the processing constraints were resolved by the purchaser, by the end of the third quarter of 2012.

Average Sales Prices

	Year ended December 31,			
	2012	2011	Change	Percent Change
Average sales prices (before hedging):				
Crude oil (Bbl)	$ 102.79	$ 101.55	$ 1.24	1.2%
Natural gas (Mcf)	2.64	3.89	(1.25)	-32.1%
Natural gas liquids (Bbl)	36.12	48.96	(12.84)	-26.2%
Natural gas equivalents (Mcfe)	7.71	6.41	1.30	20.3%

	Year ended December 31,			
	2012	2011	Change	Percent Change
Average sales prices (after hedging):				
Crude oil (Bbl)	$ 104.24	$ 92.65	$ 11.59	12.5%
Natural gas (Mcf)	3.39	4.85	(1.46)	-30.1%
Natural gas liquids (Bbl)	36.12	48.35	(12.23)	-25.3%
Natural gas equivalents (Mcfe)	8.21	6.86	1.35	19.7%

Crude oil, natural gas and natural gas liquids prices are reported net of the realized effect of our hedging agreements. We realized gains of $1.1 million on our crude oil hedges and $5.9 million on our natural gas hedges in 2012, compared to realized losses of $3.8 million on our crude oil and natural gas liquids hedges and gains of $11.3 million on our natural gas hedges in 2011. The $0.5 million decrease in net realized hedging gains for 2012 was primarily due to lower gains on natural gas hedges, offset in part by an increased amount of barrels of crude oil hedged at more favorable pricing.

Costs and Expenses

	Year ended December 31, 2012	2011	Change	Percent Change
Selected Operating Expenses:	(in millions, except percentages)			
Lease operating expenses	$ 15.3	$ 13.3	$ 2.0	15.0%
Production and ad valorem taxes	2.5	6.7	(4.2)	-62.7%
Exploration expenses	0.3	1.0	(0.7)	-70.0%
General and administrative (1)	17.2	16.5	0.7	4.2%
Cash operating expenses	35.3	37.5	(2.2)	-5.9%
Depreciation, depletion & amortization	58.8	56.9	1.9	3.3%
Share-based compensation	2.5	1.9	0.6	31.6%
Selected operating expenses (2)	$ 96.6	$ 96.3	$ 0.3	0.3%

(1) Total general and administrative costs on the Consolidated Statements of Operations include share-based compensation.
(2) Exclusive of impairments, abandonments and gains or losses on sales of assets.

	Year ended December 31, 2012	2011	Change	Percent Change
Selected Operating Expenses ($ per Mcfe):	(in millions, except percentages)			
Lease operating expenses	$ 1.08	$ 0.80	$ 0.28	35.0%
Production and ad valorem taxes	0.18	0.41	(0.23)	-56.1%
Exploration expenses	0.02	0.06	(0.04)	-66.7%
General and administrative(1)	1.22	1.00	0.22	22.0%
Cash operating expenses	2.50	2.27	0.23	10.1%
Depreciation, depletion & amortization	4.16	3.44	0.72	20.9%
Share-based compensation	0.18	0.12	0.06	50.0%
Selected operating expenses ($ per Mcfe) (2)	$ 6.84	$ 5.83	$ 1.01	17.3%

(1) Total general and administrative costs on the Consolidated Statements of Operations include share-based compensation.
(2) Exclusive of impairments, abandonments and gains or losses on sales of assets.

Lease Operating Expenses. Lease operating expenses in 2012 were $15.3 million ($1.08 per Mcfe) compared to $13.3 million ($0.80 per Mcfe) in 2011, an increase resulting from higher operating well count, higher costs and increased workover expenses. The increase on a per Mcfe basis is primarily due to the lower equivalent production volumes and higher lifting costs associated with oil production compared to natural gas production.

Production and Ad Valorem Tax Expenses. Production and ad valorem tax expenses in 2012 were $2.5 million compared to $6.7 million in 2011, a decrease primarily due to a $4.1 million severance tax refund from the State of Texas associated with the allowance of certain 2007- 2012 marketing cost deductions.

Exploration Expenses. Exploration expenses were $0.3 million in 2012 compared to $1.0 million in 2011, a decrease primarily due to positive differences between settled asset retirement obligations and actual expenses incurred in 2012 compared to 2011.

Depreciation, Depletion and Amortization ("DD&A"). DD&A expense in 2012 was $58.8 million compared to $56.9 million in 2011, an increase primarily due to a higher DD&A rate associated with our recently developed crude oil wells, offset in part by lower equivalent production.

Impairment and Abandonment of Oil and Gas Properties. Non-cash impairment and abandonment of oil and gas properties in 2012 was $117.9 million compared to $15.0 million in 2011. The impairments in 2012 were caused by a continuing depressed natural gas and natural gas liquids price environment and our decision in the fourth quarter to reduce future drilling and development capital in South and East Texas resulting in a decrease in expected future cash flows from our conventional gas fields in South Texas and our unconventional gas field in East Texas.

General and Administrative ("G&A") Expenses. Total G&A expenses were $19.7 million ($1.40 per Mcfe) in 2012 compared to $18.4 million ($1.12 per Mcfe) in 2011, which includes non-cash stock expense of $2.5 million ($0.18 per Mcfe) and $1.9 million ($0.12 per Mcfe) in 2012 and 2011, respectively. G&A expenses increased primarily due to higher office facility costs.

Interest Expense. Interest expense was $25.3 million in 2012 compared to $25.1 million in 2011. Total interest expense remained relatively flat as a result of increased borrowings under our senior secured revolving credit agreement offset by lower effective interest rates. Interest expense capitalized in 2012 and 2011 was approximately zero and $0.2 million, respectively.

Other Income (Expense) and Financing Costs. Other income and financing costs were $0.6 million in 2012 compared with $1.6 million in 2011. These expenses are comprised primarily of the amortization of capitalized costs associated with our credit facilities and commitment fees related to the undrawn availability under our senior secured revolving credit agreement.

Unrealized (Loss) Gain on Derivative Instruments. The non-cash unrealized loss in 2012 was $2.3 million compared to a non-cash unrealized gain of $0.5 million in 2011. Unrealized gain or loss on derivative instruments is the change in the fair value of our commodity price hedging contracts and our interest rate swaps during the period. Unrealized gain or loss will vary period to period, and will be a function of hedges in place, the strike prices of those hedges and the forward curve pricing for the commodities and interest rates being hedged.

Income Taxes. Our net loss before income taxes was $126.7 million in 2012 compared to $23.9 million in 2011. After adjusting for permanent tax differences, we recorded an income tax benefit of $34.7 million in 2012, compared to $8.1 million in 2011. The income tax benefit of $34.7 million includes a $10.2 million tax expense related to a partial valuation allowance against net operating loss carryforwards. We recorded this partial valuation allowance as we have not been able to realize significant amounts of net operating loss carryforwards in recent years nor do we expect that we will be able to realize a significant amount in 2013.

Year Ended December 31, 2011 Compared to Year Ended December 31, 2010

Revenues

	Year Ended December 31,			
	2011	**2010**	**Change**	**Percent Change**
Product revenues:	(in millions, except percentages)			
Natural gas sales	$ 56.7	$ 59.9	$ (3.2)	-5.3%
Crude oil sales	36.8	22.0	14.8	67.3%
Natural gas liquids sales	20.2	14.0	6.2	44.3%
Product revenues	$ 113.7	$ 95.9	$ 17.8	18.6%

Crude oil, natural gas and Natural Gas Liquids Sales. Revenues from the sale of crude oil, natural gas and natural gas liquids, net of the realized effects of our hedging instruments, were $113.7 million in 2011 compared to $95.9 million in 2010, an increase due primarily to a 28% increase in production, offset in part by an 8% decrease in realized commodity prices.

Production

	Year Ended December 31,			
	2011	**2010**	**Change**	**Percent Change**
Sales volumes:				
Natural gas (Mcf)	11,675,602	9,285,574	2,390,028	25.7%
Crude oil (Bbl)	396,760	260,289	136,471	52.4%
Natural gas liquids (Bbl)	417,956	346,327	71,629	20.7%
Natural gas equivalents (Mcfe)	16,563,898	12,925,270	3,638,628	28.2%

Production was approximately 16.6 Bcfe in 2011 compared to 12.9 Bcfe in 2010. On a daily basis, we produced an average of 45,381 Mcfe per day in 2011 compared to an average of 35,412 Mcfe per day in 2010, an increase of approximately 28% primarily due to the success of our drilling and workover programs in Southeast, South, and East Texas.

Average Sales Prices

	Year ended December 31,			
	2011	2010	Change	Percent Change
Average sales prices (before hedging):				
Natural gas (Mcf)	$ 3.89	$ 4.35	$ (0.46)	-10.6%
Crude oil (Bbl)	101.55	79.05	22.50	28.5%
Natural gas liquids (Bbl)	48.96	40.57	8.39	20.7%
Natural gas equivalents (Mcfe)	6.41	5.80	0.61	10.5%

	Year ended December 31,			
	2011	2010	Change	Percent Change
Average sales prices (after hedging):				
Natural gas (Mcf)	$ 4.85	$ 6.45	$ (1.60)	-24.8%
Crude oil (Bbl)	92.65	84.61	8.04	9.5%
Natural gas liquids (Bbl)	48.35	40.57	7.78	19.2%
Natural gas equivalents (Mcfe)	6.86	7.42	(0.56)	-7.5%

Crude oil, natural gas and natural gas liquids prices are reported net of the realized effect of our hedging agreements. We realized gains of $11.3 million on our natural gas hedges and losses of $3.8 million on our crude oil and natural gas liquids hedges in 2011, compared to realized gains of $19.5 million on our natural gas hedges and $1.4 million on our crude oil hedges in 2010. The decrease in realized hedging results for 2011 was due to the expiration in 2010 of more favorable natural gas hedges put in place during a higher commodity price environment.

Costs and Expenses

	Year ended December 31,			
	2011	2010	Change	Percent Change
Selected Operating Expenses:	(in millions, except percentages)			
Lease operating expenses	$ 13.3	$ 15.0	$ (1.7)	-11.3%
Production and ad valorem taxes	6.7	6.1	0.6	9.8%
Exploration expenses	1.0	1.0	—	0.0%
General and administrative(1)	16.5	18.1	(1.6)	-8.8%
Cash operating expenses	37.5	40.2	(2.7)	-6.7%
Depreciation, depletion & amortization	56.9	45.0	11.9	26.4%
Share-based compensation	1.9	1.8	0.1	5.6%
Selected operating expenses [(2)]	$ 96.3	$ 87.0	$ 9.3	10.7%

(1) Total general and administrative costs on the Consolidated Statements of Operations include share-based compensation.
(2) Exclusive of impairments, abandonments and gains or losses on sales of assets.

	Year ended December 31,			
	2011	2010	Change	Percent Change
Selected Operating Expenses ($ per Mcfe):	(in millions, except percentages)			
Lease operating expenses	$ 0.80	$ 1.16	$ (0.36)	-31.0%
Production and ad valorem taxes	0.41	0.47	(0.06)	-12.8%
Exploration expenses	0.06	0.07	(0.01)	-14.3%
General and administrative (1)	1.00	1.40	(0.40)	-28.6%
Operating expenses	2.27	3.10	(0.83)	-26.8%
Depreciation, depletion & amortization	3.44	3.48	(0.04)	-1.1%
Share-based compensation	0.12	0.14	(0.02)	-14.3%
Selected operating expenses ($ per Mcfe)(2)	$ 5.83	$ 6.72	$ (0.89)	-13.2%

(1) Total general and administrative costs on the Consolidated Statements of Operations include share-based compensation.
(2) Exclusive of impairments, abandonments and gains or losses on sales of assets.

Lease Operating Expenses. Lease operating expenses in 2011 were $13.3 million ($0.80 per Mcfe) compared to $15.0 million ($1.16 per Mcfe) in 2010, a decrease primarily due to non-core properties sold in 2010, sales tax refunds and lower expense workover costs in 2011.

Production and Ad Valorem Tax Expenses. Production and ad valorem tax expenses in 2011 were $6.7 million compared to $6.1 million in 2010, an increase due to higher production and field commodity prices in 2011.

Exploration Expenses. Exploration expenses were $1.0 million in 2011 and $1.0 million in 2010.

Depreciation, Depletion and Amortization ("DD&A"). DD&A expense in 2011 was $56.9 million compared to $45.0 million in 2010, an increase primarily due to higher production, offset in part by a slightly lower DD&A rate.

Impairment and Abandonment of Oil and Gas Properties. Non-cash impairment and abandonment of oil and gas properties in 2011 was $15.0 million compared to $22.3 million in 2010, primarily due to the impairment of expiring unproved leasehold cost in East Texas. Non-cash impairment expenses include amortization of individually insignificant properties.

General and Administrative ("G&A") Expenses. Total G&A expenses were $18.4 million ($1.12 per Mcfe) in 2011 compared to $19.9 million ($1.54 per Mcfe) in 2010, which includes non-cash stock expense of $1.9 million ($0.12 per Mcfe) and $1.8 million ($0.14 per Mcfe) in 2011 and 2010, respectively. G&A expenses decreased primarily due to lower personnel costs and lower legal and other professional fees.

Loss on Sale of Assets. The loss on sale of assets during 2010 of $1.1 million was primarily the result of the sale of our non-core Palo Pinto properties in Southeast Texas and the final settlement on the 2009 sale of our non-core Southwest Louisiana properties.

Interest Expense. Interest expense was $25.1 million ($1.52 per Mcfe) in 2011 compared to $22.3 million ($1.73 per Mcfe) in 2010. Total interest expense increased primarily due to the refinancing and expanding of our second lien credit agreement in December 2010. Interest expense capitalized in 2011 and 2010 was approximately $0.2 million and $0.1 million, respectively.

Other Income (Expense) and Financing Costs. Other income and financing costs were $1.6 million in 2011 compared with $4.3 million in 2010. These expenses are comprised primarily of the amortization of capitalized costs associated with our credit facilities and commitment fees related to the undrawn availability under our senior secured revolving credit agreement.

Unrealized (Loss) Gain on Derivative Instruments. The non-cash unrealized gain in 2011 was $0.5 million compared with a non-cash unrealized loss of $6.5 million in 2010. Unrealized gain or loss on derivative instruments is the change in the fair value of our commodity price hedging contracts and our interest rate swaps during the period. Unrealized gain or loss will vary period to period, and will be a function of hedges in place, the strike prices of those hedges and the forward curve pricing for the commodities and interest rates being hedged.

Income Taxes. Our net loss before taxes was $23.9 million in 2011 compared to $47.5 million in 2010. After adjusting for permanent tax differences, we recorded an income tax benefit of $8.1 million in 2011, compared to $16.6 million in 2010.

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 crude oil, natural gas 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 to which we are entitled 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.

Depreciation, depletion and amortization

The estimates of crude oil, natural gas 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 crude oil, natural gas 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 crude oil, natural gas 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

Proved natural gas and crude oil properties are assessed quarterly on a field-by-field basis for indicators of impairment, such as decreases in commodity prices, production or reserves or relinquished acreage. Proved natural gas and crude oil properties are tested for impairments when impairment indicators indicate a possible decline in the recoverability of the carrying value of such property. 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. Estimated fair values are determined using discounted cash flow models and appropriate market data. The discounted cash flow models include management's estimates of future oil and gas production, commodity prices based on forward commodity price curves as of the date of the estimate, operating and development costs, and discount rates. Appropriate market data may include recent transactions for similar properties or a dollar amount for hydrocarbon reserves or production.

Unproved properties whose acquisition costs are individually significant are assessed for impairment quarterly on a property-by-property basis. Unproved properties whose acquisition costs are not individually 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. See Note 4 - "Oil and Gas Properties" for further information.

See the discussion of impairment expenses in "Management's Discussion and Analysis of Financial Condition and Results of Operations."

Asset Retirement Obligations

We recognize an estimated liability for the plugging and abandonment of our crude oil, natural gas 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.

Income Taxes

We are subject to income and other related taxes in areas in which we operate. When recording income tax expense, certain estimates are required by management due to timing and the impact of future events on when income tax expenses and benefits are recognized by us. Accounting for uncertainty in income taxes 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.

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. Deferred tax assets are reduced by a valuation allowance when, in the opinion of management, it is more likely than not that some portion or all of the deferred tax assets will not be realized. Estimating the amount of the valuation allowance is dependent on estimates of future taxable income, alternative minimum tax income and changes in stockholder ownership that limit the use of net operating losses under the Internal Revenue Code Section 382.

Our federal and state income tax returns are generally not filed before the consolidated financial statements are prepared. Therefore we estimate the tax basis of our assets and liabilities at the end of each period as well as the effects of tax rate changes, tax credits and net operating and capital loss carryforwards and carrybacks. Adjustments related to differences between the estimates we used and actual amounts we reported are recorded in the period in which we file our income tax returns.

We have a significant deferred tax asset associated with our net tax operating losses. 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. We expect we will not be able to utilize certain deferred tax assets due to the limitations of Internal Revenue Code Section 382 and we have recognized a valuation allowance for that limitation. We will continue to assess the need for a valuation allowance against deferred tax assets considering all available evidence obtained in future reporting periods. Any adjustments or changes in our estimates of asset recovery could have an impact on our results of operations. See Item 8. "Financial Statements and Supplementary Data, Note 15 - Income Taxes and Schedule II–Valuation and Qualifying Accounts."

Recent Accounting Pronouncements

Accounting Standards Not Yet Adopted

In December 2011, the FASB issued Accounting Standards Update No. 2011-11 "Balance Sheet (Topic 210): Disclosures about Offsetting Assets and Liabilities". This accounting update requires that an entity disclose information about offsetting and related arrangements to enable users of its financial statements to understand the effect of those arrangements on its financial position. The accounting update is effective for annual periods beginning on or after January 1, 2013. We are currently evaluating the provisions of this accounting update and assessing the impact, if any, it may have on our financial position and results of operations.

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 2013 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, 2012:

	Long-term debt	Interest(1)	Operating leases(2)	Asset retirements	Employment agreements	Uncertain income tax positions(3)
2013	$ —	$ 24,114,938	$ 2,301,131	$ 876,774	$ 2,066,726	$ —
2014	—	24,114,938	1,050,151	593,333	901,439	—
2015	244,102,161	22,736,735	947,916	862,202	157,328	—
2016	—	—	961,813	702,608	—	—
2017	—	—	975,711	541,785	—	—
Thereafter	—	—	1,237,878	7,452,504	—	518,219
Total	$ 244,102,161	$ 70,966,611	$ 7,474,600	$ 11,029,206	$ 3,125,493	$ 518,219

(1) Estimated interest is based on the outstanding debt at December 31, 2012 using the interest rate in effect at that time.

(2) Operating leases include contracts related to office space, compressors, vehicles, office equipment and other. Operating lease commitments exclude a sublease of office space that is expected to reduce operating lease expense in 2013 and 2014 by approximately $1.0 million and $85,000, respectively

(3) 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.

Liquidity and Capital Resources

Our primary cash requirements 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, net of the realized effect of our hedging agreements, and amounts available to be drawn under our senior secured revolving credit agreement. 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 or asset monetization, or the curtailment of capital expenditures.

Liquidity and Cash Flow

Our working capital deficit was $13.9 million as of December 31, 2012, compared to a working capital deficit of $46.0 million as of December 31, 2011. The reduction in working capital deficit is primarily driven by reduced drilling activity in the fourth quarter of 2012 compared to the fourth quarter of 2011. The following table provides the components and changes in working capital as of December 31, 2012 and December 31, 2011.

	2012	2011	Change
Current assets			
Accounts receivable, net	$ 11.7	$ 16.1	$ (4.4)
Prepaid expenses	0.8	0.5	0.3
Derivative instruments	1.9	4.5	(2.6)
Deferred tax asset, net	10.4	—	10.4
Total current assets	24.8	21.1	3.7
Current liabilities			
Accounts payable and accrued liabilities	37.8	65.7	(27.9)
Asset retirement obligations	0.9	0.9	—
Derivative instruments	—	0.3	(0.3)
Deferred tax liability, net	—	0.2	(0.2)
Total current liabilities	38.7	67.1	(28.4)
Working capital (deficit)	$ (13.9)	$ (46.0)	$ 32.1

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 years ended December 31, 2012, 2011 and 2010, respectively.

	Year ended December 31,		
	2012	2011	2010
		(in millions)	
Net cash provided by operating activities	$ 31.3	$ 71.7	$ 48.0
Net cash used in investing activities	(78.9)	(88.5)	(54.9)
Net cash provided by financing activities	47.7	16.8	6.9
Cash and cash equivalents	—	—	—

During 2012, the net cash provided by operating activities, before changes in working capital, increased to $55.2 million, from $51.3 million for 2011, primarily due to lower severance taxes in 2012 from a $4.1 million severance tax refund from the State of Texas.

Net cash used in investing activities consists primarily of capital expenditures on oil and gas drilling projects and leasehold acquisitions.

Net cash provided by financing activities, which consists primarily of net borrowings/repayments on our senior secured revolving credit agreement, was $47.7 million for the twelve months ended December 31, 2012 compared to net cash provided by financing activities of $16.8 million for the twelve months ended December 31, 2011, an increase primarily due to lower cash flows from operating activities.

See the Consolidated Statements of Cash Flows for further details.

Capital Resources

We maintain a senior secured revolving credit agreement with Wells Fargo Bank, National Association ("*Wells Fargo Bank*"), as agent, and the lender parties thereto (the "*Senior Credit Agreement*") that matures on May 31, 2015. The borrowing base currently set at $100 million, is based on our current proved crude oil and natural gas reserves, and is subject to semi-annual redeterminations, although our lenders may elect to make one additional unscheduled redetermination between scheduled redetermination dates. The next borrowing base redetermination under our Senior Credit Agreement is scheduled for May 1, 2013. The credit agreement also provides for the issuance of letters-of-credit up to a $5.0 million sub-limit. As of December 31, 2012, we had $69.2 million outstanding, with availability of $30.8 million under our Senior Credit Agreement.

Advances under our Senior 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. The applicable margin ranges between 1.75% and 2.75%, for LIBOR loans, and between 0.75% and 1.75%, 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 nine months may be selected. The commitment fee payable on the unused portion of our borrowing base is between 0.375% and 0.500%, depending on the borrowing base utilization.

We also maintain a second lien credit agreement dated December 27, 2010 with Barclays Bank Plc, as agent, and the lender parties thereto, including an affiliate of OCM GW Holdings, LLC ("*Oaktree Holdings*"), our largest stockholder (the "*Second Lien Credit Agreement*"). The Second Lien Credit Agreement provides for a term loan, made to us in a single draw, in an aggregate principal amount of $175.0 million and matures on December 27, 2015. As of December 31, 2012, we had a principal amount of $175.0 million outstanding, with a discount of $4.7 million using the estimated market value interest rate at the time of issuance, for a net reported balance of $170.3 million.

Advances under our 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 Senior 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 Senior Credit Agreement. Unpaid interest is payable under our Senior Credit Agreements as interim borrowings mature and renew.

As required by our Second Lien Credit Agreement, we employ the use of swaps and costless collar derivative instruments to limit our exposure to commodity prices. We currently have 6.3 Bcfe of equivalent production hedged for 2013, consisting of 297 MBbl of crude oil hedges at Brent prices, 168 MBbl of crude oil hedges at WTI prices and 3.5 Bcf of natural gas hedges at Brent prices. We also have 1.6 Bcfe of equivalent production hedged for 2014, consisting of 90 MBbl of crude oil hedges and 1.0 Bcf of natural gas hedges. See Note 6 — "Derivatives" for further information.

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, 2012, we were in compliance with the covenants under our Senior 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 crude oil, natural gas 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 resource plays in Southeast, South and East Texas and Colorado and in our conventional inventory, with activity in any particular area to be a function of market and field economics. We anticipate that acquisitions, including those of undeveloped leasehold interests, will continue to play a role in our business strategy as those opportunities 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 Senior 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 twelve months. We currently plan to initially limit our 2013 capital expenditures to our forecasted cash flow from operations for the year; however, we do possess the capacity, through our Senior Credit Agreement, to increase and/or accelerate drilling on any particular area should we determine that market and project economics so warrant. The substantial majority of our planned capital expenditures for 2013 are on acreage that is currently held by existing production, therefore, we also possess the flexibility of reducing our capital expenditures, if deemed appropriate. 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 commodity price volatility, which could, among other things, lead to a decline in the borrowing base under our Senior Credit Agreement in connection with a borrowing base redetermination. In addition, if any lender under our Senior Credit Agreement is unable to fund their commitment, our liquidity could be reduced by an amount up to the aggregate amount of such lender's commitment under our Senior Credit Agreement. In such case, we may be required to seek other sources of capital earlier than anticipated. Restrictions in our Senior 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 Item 1A. "Risk Factors" for further information.

Our 2013 capital budget is currently forecasted to be approximately $58.7 million, exclusive of acquisitions, if any, focusing on our inventory of crude oil and liquids-rich projects in the Woodbine formation with a continuous rig program planned for 2013. We also currently plan to drill one or more test wells in the crude oil play in the Buda formation in the Zavala/Dimmit counties in South Texas.

Inflation and Changes in Prices

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

The following table indicates the average quarterly crude oil, natural gas and natural gas liquids prices 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 crude oil, natural gas and natural gas liquids prices.

	Average Prices (1)			
	Crude Oil (per Bbl)	Natural Gas (per Mcf)	Natural Gas Liquids (per Bbl)	Per Equivalent Mcf
2012				
First	$ 106.49	$ 3.27	$ 43.57	$ 7.64
Second	109.06	3.02	35.95	8.30
Third	97.27	3.57	31.05	8.63
Fourth	105.91	3.77	35.02	8.24
2011				
First	$ 84.53	$ 4.88	$ 44.17	$ 6.44
Second	97.77	4.75	47.86	6.69
Third	89.99	5.00	51.66	6.96
Fourth	96.86	4.78	50.80	7.45
2010				
First	$ 83.77	$ 6.96	$ 46.25	$ 7.90
Second	84.66	6.91	38.99	7.77
Third	84.76	6.47	34.60	7.21
Fourth	85.02	5.74	43.64	7.02

(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, 2012, 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 shown under operating leases in the commitments and contingencies table, we have no other arrangements that are reasonably likely to materially affect our liquidity or availability of or requirements for capital resources.

ITEM 7A. QUALITATIVE AND QUANTITATIVE DISCLOSURES ABOUT MARKET RISK

The following market risk disclosures should be read in conjunction with our financial statements and notes thereto beginning on Page F-1 of this Annual Report on Form 10-K. All of our financial instruments are for purposes other than trading. Hypothetical changes in interest rates and prices chosen for the following simulated sensitivity effects are considered to be reasonably possible near-term changes generally based on consideration of past fluctuations for each risk category. It is not possible to accurately predict future changes in interest rates and product prices. Accordingly, these hypothetical changes may not be an indicator of probable future fluctuations. See Note 6 - "Derivative Instruments" to our consolidated financial statements included herein for further information.

Commodity Price Risk

In the past we have entered into, and may in the future enter into, certain derivative arrangements with respect to portions of our crude oil, natural gas and natural gas liquids production, to reduce our sensitivity to volatile commodity prices. 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 crude oil, natural gas and natural gas liquids. Moreover, our derivative arrangements apply only to a portion of our production and provide only partial protection against declines in commodity prices. Such arrangements may expose us to risk of financial loss in certain circumstances. We expect that the monthly volume of derivative arrangements will vary from time to time. We continuously reevaluate our derivative hedging program in light of increases in production, market conditions, commodity price forecasts, capital spending and debt service requirements.

At December 31, 2012, we had entered into swaps, puts and costless collars related to future crude oil and natural gas sales with a net fair value of $2.0 million. A price increase of $1.00 per Bbl of crude oil would decrease the net fair value of our commodity derivatives by $0.3 million. A price increase of $0.10 per MMBtu for natural gas would decrease the net fair value of our commodity derivatives by approximately $0.3 million.

Interest Rate Risk

We are exposed to interest rate risk on debt with variable interest rates. In the past we have entered into, and may in the future enter into, interest rate swap agreements. Changes in interest rates affect the amount of interest we pay on borrowings under our Senior Credit Agreement. At December 31, 2012, we did not have any outstanding interest rate swap agreements. Assuming our current level of borrowings, a 100 basis point increase in the interest rates we pay under our Senior Credit Agreement would result in an increase of our interest expense by $0.7 million for a twelve month period, assuming current debt levels.

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 year ended December 31, 2012, 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, 2012 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.

The independent auditor’s report on internal control over financial reporting as of December 31, 2012 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.

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, 2012.

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, 2012.

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, 2012.

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, 2012.

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, 2012.

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.

Boe. Barrel of oil equivalent per day determined using the ratio of six Mcf of natural gas to one Bbl of crude oil, condensate or natural gas liquids.

Boe/d. Boe per day.

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. One MMBtu equates to one Mcf.

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 producing reserves. Proved developed oil and gas reserves are reserves that can be expected to be recovered through existing wells with existing equipment and operating methods.

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.

PV-10. A non-GAAP financial measure that represents the present value, discounted at 10% per year, of estimated future cash inflows from proved natural gas and crude oil reserves, less future development and production costs using pricing assumptions in effect at the end of the period. PV-10 differs from Standardized Measure of Discounted 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 of Discounted Net Cash Flows represents an estimate of fair market value of natural gas and crude oil properties. PV-10 is used by the industry 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.

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
Reports of Independent Registered Public Accounting Firm
Consolidated Balance Sheets at December 31, 2012 and 2011
Consolidated Statements of Operations for the years ended December 31, 2012, 2011 and 2010
Consolidated Statements of Stockholders' Equity for the years ended December 31, 2012, 2011 and 2010
Consolidated Statements of Cash Flows for the years ended December 31, 2012, 2011 and 2010
Notes to Consolidated Financial Statements

(2) Financial Statement Schedule:

Schedule II - Valuation and Qualifying Accounts

(3) Exhibits:

Number	Description
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 File No. 001-12108)
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 File No. 000-21644)
3.3	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 File No. 001-12108)
4.1	Form of Common Stock Certificate (incorporated by reference to Exhibit 3.8 to the Company's Current Report on Form 8-K filed July 5, 2005 File No. 001-12108)
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 File No. 001-12108)
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 File No. 005-54301)
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 File No. 005-54301)
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 File No. 001-12108)
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 File No. 001-12108)

ITEM 15. EXHIBITS AND FINANCIAL STATEMENT SCHEDULES. (CONTINUED)

Number	Description
#10.1	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 File No. 001-12108)
#10.2	Form of executive officer restricted stock grant for grants outside the Crimson Exploration Inc. 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 File No. 000-21644)
10.3	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 File No. 001-12108)
10.4	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 book runners, 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 File No. 000-21644)
10.5	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 File No. 000-21644)
10.6	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 File No. 000-21644)
10.7	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 File No. 000-21644)
10.8	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 File No. 001-12108)
10.9	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 File No. 001-12108)
10.10	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 File No. 001-12108)

ITEM 15. EXHIBITS AND FINANCIAL STATEMENT SCHEDULES. (CONTINUED)

Number	Description
10.11	Seventh Amendment, dated as of May 17, 2012, 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 May 22, 2012 File No. 001-12108)
10.12	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 File No. 001-12108)
10.13	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 File No. 001-12108)
#10.14	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 File No. 000-21644)
#10.15	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 File No. 000-21644)
#10.16	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 File No. 000-21644)
#10.17	Long-Term Incentive 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 File No. 000-21644)
#10.18	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 File No. 000-21644)
#10.19	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 File No. 000-21644)
#10.20	Long-Term Incentive Performance Plan Form of 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 File No. 000-21644)
#10.21	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 File No. 000-21644)
#10.22	First Amendment to the Amended and Restated 2005 Stock Incentive Plan (Incorporated by reference to Exhibit B to the Company's definitive proxy statement on Schedule 14A filed on April 13, 2011 File No. 001-12108)
#10.23	Second Amendment to the Amended and Restated 2005 Stock Incentive Plan (Incorporated by reference to Exhibit C to the Company's definitive proxy statement on Schedule 14A filed on April 13, 2011 File No. 001-12108)

ITEM 15. EXHIBITS AND FINANCIAL STATEMENT SCHEDULES. (CONTINUED)

Number	Description
#10.24	Amended and Restated Employment Agreement between Allan D. Keel and Crimson Exploration Inc., dated June 29, 2011 (incorporated by reference to Exhibit 10.1 to the Company's Report on Form 8-K filed on July 12, 2011 File No. 001-12108)
#10.25	Amended and Restated Employment Agreement between E. Joseph Grady and Crimson Exploration Inc., dated June 29, 2011 (incorporated by reference to Exhibit 10.2 to the Company's Report on Form 8-K filed on July 12, 2011 File No. 001-12108)
#10.26	Amended and Restated Employment Agreement between Thomas H. Atkins and Crimson Exploration Inc., dated June 29, 2011 (incorporated by reference to Exhibit 10.3 to the Company's Report on Form 8-K filed on July 12, 2011 File No. 001-12108)
#10.27	Amended and Restated Employment Agreement between Jay S. Mengle and Crimson Exploration Inc., dated June 29, 2011 (incorporated by reference to Exhibit 10.4 to the Company's Report on Form 8-K filed on July 12, 2011 File No. 001-12108)
# 10.28	Amended and Restated Employment Agreement between Carl Isaac and Crimson Exploration Inc., dated April 18, 2012 (incorporated by reference to Exhibit 10.1 to the Company's Current Report on Form 8-K filed on April 19, 2012 File No. 001-12108)
#10.29	Summary terms of Director Compensation Plan, as amended (incorporated by reference to Exhibit 10.3 to the Company's Quarterly Report on Form 10-Q for the quarter ended June 30, 2012 File No. 001-12108)
*12.1	Statement of Computation of Ratio of Earnings to Fixed Charges
*21.1	Significant Subsidiaries of the Registrant
*23.1	Consent of Grant Thornton LLP — Independent Registered Public Accounting Firm
*23.2	Consent of Netherland, Sewell & Associates, Inc.
*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, 2012 provided by Netherland, Sewell and Associates, Inc.

ITEM 15. EXHIBITS AND FINANCIAL STATEMENT SCHEDULES. (CONTINUED)

Number	Description
*101.INS	XBRL Instance Document
*101.SCH	XBRL Schema Document
*101.CAL	XBRL Calculation Linkbase Document
*101.LAB	XBRL Labels Linkbase Document
*101.PRE	XBRL Presentation Linkbase Document
*101.DEF	XBRL Definition Linkbase Document

* Filed herewith
** Furnished herewith
\# Denotes 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 15, 2013

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 (Principal Executive Officer)	March 15, 2013
/s/ E. Joseph Grady E. Joseph Grady	Senior Vice President and Chief Financial Officer (Principal Financial Officer)	March 15, 2013
/s/ Paul F. Jansen Paul F. Jansen	Controller and Chief Accounting Officer (Principal Accounting Officer)	March 15, 2013
/s/ B. James Ford B. James Ford	Director	March 15, 2013
/s/ Lon McCain Lon McCain	Director	March 15, 2013
/s/ Lee B. Backsen Lee B. Backsen	Director	March 15, 2013
/s/ Adam C. Pierce Adam C. Pierce	Director	March 15, 2013
/s/ Cassidy J. Traub Cassidy J. Traub	Director	March 15, 2013
/s/ Ni Zhaoxing Ni Zhaoxing	Director	March 15, 2013

CRIMSON EXPLORATION INC.

FINANCIAL REPORT

DECEMBER 31, 2012

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, 2012. 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, 2012.

/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 15, 2013

Report of Independent Registered Public Accounting Firm

Board of Directors and Shareholders
Crimson Exploration Inc.

We have audited the accompanying consolidated balance sheets of Crimson Exploration Inc. (a Delaware corporation) and subsidiaries (the "Company") as of December 31, 2012 and 2011, and the related consolidated statements of operations, shareholders' equity, and cash flows for each of the three years in the period ended December 31, 2012. Our audits of the basic consolidated financial statements included the financial statement schedule listed in the index appearing under Item 15. These financial statements and financial statement schedule are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements and financial statement schedule 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. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes 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, 2012 and 2011, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2012 in conformity with accounting principles generally accepted in the United States of America. Also in our opinion, the related financial statement schedule, when considered in relation to the basic consolidated financial statements taken as a whole, presents fairly, in all material respects, the information set forth therein.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the Company's internal control over financial reporting as of December 31, 2012, based on criteria established in *Internal Control—Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO), and our report dated March 15, 2013 expressed an unmodified opinion.

/s/ GRANT THORNTON LLP

Houston, Texas
March 15, 2013

Report of Independent Registered Public Accounting Firm

Board of Directors and Shareholders
Crimson Exploration Inc.

We have audited the internal control over financial reporting of Crimson Exploration Inc. (a Delaware corporation) and subsidiaries (the "Company") as of December 31, 2012, based on criteria established in *Internal Control—Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). The Company's management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting, included in the accompanying Report of Management on Internal Control Over Financial Reporting. Our responsibility is to express an opinion on the Company's internal control over financial reporting based on our audit.

We conducted our audit 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 effective internal control over financial reporting was maintained in all material respects. Our audit included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, testing and evaluating the design and operating effectiveness of internal control based on the assessed risk, and performing such other procedures as we considered necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinion.

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

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

In our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2012, based on criteria established in *Internal Control—Integrated Framework* issued by COSO.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the consolidated financial statements of the Company as of and for the year ended December 31, 2012, and our report dated March 15, 2013 expressed an unqualified opinion on those financial statements.

/s/ GRANT THORNTON LLP

Houston, Texas
March 15, 2013

PART I. FINANCIAL INFORMATION

ITEM 1. FINANCIAL STATEMENTS.

CRIMSON EXPLORATION INC. AND SUBSIDIARIES
CONSOLIDATED BALANCE SHEETS
ASSETS

	December 31, 2012	December 31, 2011
CURRENT ASSETS		
Cash and cash equivalents	$ —	$ —
Accounts receivable, net of allowance $525,556 and $579,588, respectively	11,726,078	16,059,667
Prepaid expenses	844,495	473,616
Derivative instruments	1,892,744	4,538,897
Deferred tax asset	10,361,157	—
Total current assets	24,824,474	21,072,180
PROPERTY AND EQUIPMENT		
Oil and gas properties (successful efforts method of accounting)	740,070,145	663,414,446
Other property and equipment	3,061,635	3,345,798
Accumulated depreciation, depletion and amortization	(442,304,300)	(269,978,945)
Total property and equipment, net	300,827,480	396,781,299
NONCURRENT ASSETS		
Deposits	34,743	34,743
Debt issuance cost	1,056,272	1,140,031
Derivative instruments	67,261	—
Deferred tax asset	41,810,159	17,297,621
Total noncurrent assets	42,968,435	18,472,395
TOTAL ASSETS	$ 368,620,389	$ 436,325,874

LIABILITIES AND STOCKHOLDERS' EQUITY

	December 31, 2012	December 31, 2011
CURRENT LIABILITIES		
Accounts payable	$ 31,127,671	$ 49,539,258
Accrued liabilities	6,680,843	16,131,324
Asset retirement obligations	876,774	935,705
Derivative instruments	—	290,703
Deferred tax liability	—	189,146
Total current liabilities	38,685,288	67,086,136
NONCURRENT LIABILITIES		
Long-term debt	239,368,865	190,041,933
Asset retirement obligations	10,152,432	9,071,064
Other noncurrent liabilities	571,687	621,043
Total noncurrent liabilities	250,092,984	199,734,040
Total liabilities	288,778,272	266,820,176
COMMITMENTS AND CONTINGENCIES (see Note 11)		
STOCKHOLDERS' EQUITY		
Common stock (Par value $0.001; 200,000,000 shares authorized; 46,259,009 and 45,270,768 shares issued and 46,063,822 and 45,129,407 shares outstanding as of December 31, 2012 and 2011, respectively)	46,259	45,271
Additional paid-in capital	246,007,941	243,484,877
Retained deficit	(165,343,525)	(73,352,170)
Treasury stock (At cost, 195,187 and 141,361 shares as of December 31, 2012 and 2011, respectively)	(868,558)	(672,280)
Total stockholders' equity	79,842,117	169,505,698
TOTAL LIABILITIES AND STOCKHOLDERS' EQUITY	$ 368,620,389	$ 436,325,874

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,		
	2012	2011	2010
OPERATING REVENUES			
Crude oil sales	$ 78,591,313	$ 36,760,014	$ 22,021,906
Natural gas sales	26,459,983	56,666,485	59,861,551
Natural gas liquids sales	10,852,720	20,209,534	14,048,766
Total operating revenues	115,904,016	113,636,033	95,932,223
OPERATING EXPENSES			
Lease operating expenses	15,270,587	13,273,760	15,001,954
Production and ad valorem taxes	2,492,117	6,732,545	6,061,033
Exploration expenses	292,651	995,412	967,322
Depreciation, depletion and amortization	58,764,443	56,920,515	45,022,272
Impairment and abandonment of oil and gas properties	117,890,239	14,954,633	22,254,059
General and administrative	19,653,468	18,420,570	19,901,784
(Gain) loss on sale of assets	(8,900)	—	1,069,616
Total operating expenses	214,354,605	111,297,435	110,278,040
INCOME (LOSS) FROM OPERATIONS	(98,450,589)	2,338,598	(14,345,817)
OTHER INCOME (EXPENSE)			
Interest expense	(25,327,411)	(25,104,073)	(22,324,535)
Other income (expense) and financing costs	(644,755)	(1,633,170)	(4,280,859)
Unrealized (loss) gain on derivative instruments	(2,288,189)	454,906	(6,500,825)
Total other expense	(28,260,355)	(26,282,337)	(33,106,219)
LOSS BEFORE INCOME TAXES	(126,710,944)	(23,943,739)	(47,452,036)
Income tax benefit	34,719,589	8,098,357	16,607,139
NET LOSS	$ (91,991,355)	$ (15,845,382)	$ (30,844,897)
NET LOSS PER SHARE			
Basic	$ (2.08)	$ (0.35)	$ (0.78)
Diluted	$ (2.08)	$ (0.35)	$ (0.78)
WEIGHTED AVERAGE SHARES OUTSTANDING			
Basic	44,147,787	44,788,551	39,397,486
Diluted	44,147,787	44,788,551	39,397,486

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, 2012, 2011 and 2010

	NUMBER OF SHARES OUTSTANDING					
	COMMON STOCK	COMMON STOCK	ADDITIONAL PAID-IN CAPITAL	RETAINED EARNINGS (DEFICIT)	TREASURY STOCK	TOTAL STOCKHOLDERS' EQUITY
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	374,201	374	1,856,771	—	—	1,857,145
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
Current year net loss	—	—	—	(15,845,382)	—	(15,845,382)
Share-based compensation	318,363	319	1,996,128	—	—	1,996,447
Treasury stock	(46,215)	—	—	—	(176,338)	(176,338)
BALANCE, DECEMBER 31, 2011	45,129,407	45,271	243,484,877	(73,352,170)	(672,280)	169,505,698
Current year net loss	—	—	—	(91,991,355)	—	(91,991,355)
Share-based compensation	988,241	988	2,523,064	—	—	2,524,052
Treasury stock	(53,826)	—	—	—	(196,278)	(196,278)
BALANCE, DECEMBER 31, 2012	46,063,822	$ 46,259	$ 246,007,941	$ (165,343,525)	$ (868,558)	$ 79,842,117

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, 2012	2011	2010
CASH FLOWS FROM OPERATING ACTIVITIES:			
Net loss	$ (91,991,355)	$ (15,845,382)	$ (30,844,897)
Adjustments to reconcile net loss to net cash provided by operating activities:			
Depreciation, depletion and amortization	58,764,443	56,920,515	45,022,272
Asset retirement obligations	(385,942)	(392,861)	(162,668)
Stock compensation expense	2,486,492	1,935,886	1,789,031
Amortization of financing costs and discounts	1,590,692	2,321,158	4,192,875
Deferred income taxes	(35,062,841)	(8,098,357)	(16,378,441)
Impairment and abandonment of oil and gas properties	117,540,239	14,954,633	22,254,059
(Gain) loss on sale of assets	(8,900)	—	1,069,616
Unrealized loss (gain) on derivative instruments	2,288,189	(454,906)	6,500,825
Provision for bad debts	(28,495)	445	167,819
Changes in operating assets and liabilities:			
(Increase) decrease in accounts receivable, net	4,362,084	(1,534,180)	379,494
Increase in prepaid expenses	(370,879)	(304,849)	(168,766)
Increase (decrease) in accounts payable and accrued liabilities	(27,911,424)	22,148,113	14,188,815
Net cash provided by operating activities	31,272,303	71,650,215	48,010,034
CASH FLOWS FROM INVESTING ACTIVITIES:			
Capital expenditures	(79,334,481)	(87,511,475)	(54,745,840)
Acquisition of oil and gas properties	—	(954,687)	—
Sale of assets	400,900	—	(224,776)
Deposits	—	—	69,954
Net cash used in investing activities	(78,933,581)	(88,466,162)	(54,900,662)
CASH FLOWS FROM FINANCING ACTIVITIES:			
Payments on debt	(210,301,303)	(139,975,774)	(286,802,034)
Proceeds from debt	258,425,527	156,953,711	265,783,020
Proceeds from issuance of common stock	37,557	60,562	29,967,579
Debt issuance expenditures	(304,225)	(46,214)	(1,946,307)
Purchase of treasury stock	(196,278)	(176,338)	(111,630)
Net cash provided by financing activities	47,661,278	16,815,947	6,890,628
INCREASE (DECREASE) IN CASH AND CASH EQUIVALENTS	—	—	—
CASH AND CASH EQUIVALENTS, Beginning of year	—	—	—
CASH AND CASH EQUIVALENTS, End of year	$ —	$ —	$ —
Cash paid for interest	$ 24,077,674	$ 24,618,488	$ 25,982,510
Cash paid for income taxes	$ 210,000	$ —	$ 22,233

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

1. Organization and Nature of Operations

Crimson Exploration Inc., together with its subsidiaries, (*"Crimson"*, *"we"*, *"our"*, *"us"*) is an independent energy company engaged in the exploitation, exploration, development and acquisition 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 expanded our strategic focus to include longer reserve life resource plays that we believe provide significant long-term growth potential in multiple formations. We are also focusing on further developing our oil/liquid weighted assets.

We intend to grow reserves and production by developing our existing producing property base including, developing our oil/liquids resource potential in Southeast and South Texas, and by pursuing opportunistic acquisitions in areas where we have current operations and specific operating expertise. In 2012, we successfully transitioned from a predominantly natural gas weighted production profile to a current production profile of approximately 50 percent crude oil and natural gas liquids. We have developed a significant inventory of high quality drilling opportunities on our existing property base that should provide the opportunity for multiyear reserve growth. In 2013, we will continue to focus on our inventory of crude oil and liquids-rich projects in the Woodbine formation with a continuous rig program planned for 2013. We also currently plan to drill one or more test wells in the crude oil play in the Buda formation in the Zavala/Dimmit counties in South Texas. We will continue to monitor increasing industry activity in the James Lime play in East Texas and the oil weighted Niobrara Shale in the DJ Basin of Colorado to determine the future potential and strategy for optimizing value in each play prior to expending drilling capital. The results of drilling activity near our acreage will determine our strategy and activity level in these plays; and given success by nearby operators, we may adjust our capital budget to capitalize on opportunities on our acreage positions in these plays.

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.

Subsidiary Guarantee

Crimson Exploration Inc., as the parent company (the "Parent Company"), filed a registration statement on Form S-3 with the SEC to register, among other securities, debt securities that the Parent Company may issue from time to time. Crimson Exploration Operating, Inc. (the "Subsidiary") is a Co-Registrant with the Parent Company under the registration statement, and the registration statement also registered guarantees of debt securities by the Subsidiary. The Subsidiary is wholly-owned by the Parent Company and any guarantee by the Subsidiary will be full and unconditional. The Parent Company has no assets or operations independent of the Subsidiary, and there are no significant restrictions upon the ability of the Subsidiary to distribute funds to the Parent Company. The Parent Company has one other wholly-owned subsidiary that is inactive. Finally, the Parent Company's wholly-owned subsidiaries do not have restricted assets that exceed 25% of net assets as of the most recent fiscal year end that may not be transferred to the Parent Company in the form of loans, advances or cash dividends by the subsidiary without the consent of a third party.

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.

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 are capitalized pending determination of whether the well has found proved reserves in economically producible quantities. We assess the status of suspended exploratory well costs on a quarterly basis. 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). The costs of unproved leaseholds, including interest costs associated with in-progress period activities incurred prior to bringing those projects to their intended use, are capitalized pending the results of exploration efforts.

Gains and losses on disposal or retirements that are significant are included in income from operations on our Consolidated Statements of Operations.

Oil and Gas Reserves

The estimates of proved crude oil, natural gas 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 crude oil, natural gas 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 crude oil, natural gas 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 18 – "Oil and Gas Reserves (unaudited)" for further information.

Other Property and Equipment

Other property and equipment consist primarily of furniture and fixtures, field vehicles, office equipment, computer equipment and software.

Depreciation, Depletion and Amortization

Depreciation, depletion and amortization (*"DD&A"*) of capitalized drilling and development costs of producing natural gas and crude oil properties, including related support equipment and facilities and net of salvage value, are computed using the unit-of-production method on a field basis based on total estimated proved developed natural gas and crude oil reserves. Amortization of producing leaseholds is based on the unit-of-production method using total estimated proved reserves. Upon sale or retirement of properties, the cost and related accumulated depreciation, depletion and amortization are eliminated from the accounts and the resulting gain or loss, if any, is recognized. Unit-of-production rates are revised whenever there is an indication of a need, but at least annually. Revisions are accounted for prospectively as changes in accounting estimates.

Other property and equipment are depreciated using the straight-line method over their estimated useful lives which range between 3 and 13 years.

Impairment of Oil and Gas Properties

Proved natural gas and crude oil properties are assessed quarterly on a field-by-field basis for indicators of impairment, such as decreases in commodity prices, production or reserves or relinquished acreage. Proved natural gas and crude oil properties are tested for impairments when impairment indicators indicate a possible decline in the recoverability of the carrying value of such property. 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. Estimated fair values are determined using discounted cash flow models and appropriate market data. The discounted cash flow models include management's estimates of future oil and gas production, commodity prices based on forward commodity price curves as of the date of the estimate, operating and development costs, and discount rates. Appropriate market data may include recent transactions for similar properties or a dollar amount for hydrocarbon reserves or production.

Unproved properties whose acquisition costs are individually significant are assessed for impairment quarterly on a property-by-property basis. Unproved properties whose acquisition costs are not individually 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. See Note 4 - "Oil and Gas Properties" for further information.

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 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. See Note 8 – "Asset Retirement Obligations" for further information.

Revenue Recognition and Oil and Gas Imbalances

We follow the "sales" method of accounting for crude oil, natural gas 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 to which we are entitled 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 crude oil, natural gas 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.

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.

Accounting for Commodity Derivative Instruments

We account for our commodity derivative instruments using mark-to-market accounting and recognize all gains and losses in earnings during the period in which they occur. Derivative instruments with settlement dates within one year are presented as current whereas derivative instruments with settlement dates exceeding one year are presented as non-current. For each counterparty, we calculate a net asset or liability for current and non-current derivative instruments, respectively, based on settlement dates within the respective contracts. See Note 6 – "Derivative Instruments" for further information.

Debt Issuance Costs

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

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.

Recently Issued Accounting Standards

In December 2011, the FASB issued Accounting Standards Update No. 2011—11 “Balance Sheet (Topic 210): Disclosures about Offsetting Assets and Liabilities”. This accounting update requires that an entity disclose information about offsetting and related arrangements to enable users of its financial statements to understand the effect of those arrangements on its financial position. The accounting update is effective for annual periods beginning on or after January 1, 2013. We are currently evaluating the provisions of this accounting update and assessing the impact, if any, it may have on our financial position and results of operations.

3. Use of Estimates

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) crude oil, natural gas and natural gas liquids revenues and reserves; (2) depreciation, depletion and amortization; (3) impairment of oil and gas properties; (4) accrued assets and liabilities; (5) stock-based compensation; (6) asset retirement obligations (“*AROs*”); (7) valuation of derivative instruments and (8) valuation allowances associated with income taxes and accounts receivables. 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.

In July 2011 we changed our lease operating accrual process for direct operating expenses. The change in the accrual process was a direct result of an in depth analysis of recent historical information combined with better insight and improved judgment in estimating direct operating expenses. In accordance with Accounting Standards Codification 250 “Accounting Changes and Error Corrections” (“*ASC 250*”) we have treated the adjustment as a change in accounting estimate. A change in estimate under ASC 250 is defined as a revision in accounting measurement based on the occurrence of new events, additional experience, subsequent developments, better insight, and/or improved judgment. As required under ASC 250 regarding changes in accounting estimates, we recorded a $2.3 million reduction to accrued liabilities (and related lease operating expenses) in the “period of change” which we have interpreted to be the third quarter of 2011.

4. 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.

The following table sets forth the composition of exploration expenses for the years ended December 31:

	2012	2011	2010
Lease rental (income) expense	$ (68,205)	$ —	$ 70,839
Geological and geophysical	197,452	374,782	591,909
Settled asset retirement obligations	163,404	620,630	304,574
Total	$ 292,651	$ 995,412	$ 967,322

The following table sets forth the composition of impairment and abandonment expenses for the years ended December 31:

	2012	2011	2010
Impairment and abandonment of proved properties	$ 114,365,871	$ —	$ 473,105
Impairment and abandonment of unproved properties	3,524,368	14,954,633	21,780,954
Total	$ 117,890,239	$ 14,954,633	$ 22,254,059

2012 Asset Impairments. Non-cash impairments of proved properties include $114.4 million related to conventional gas assets in South Texas and unconventional gas assets in East Texas. See Note 5 - "Fair Value Measurements" for more details regarding the valuation methodology used to measure these impairments. Non-cash impairments of unproved properties include $3.0 million related to individually insignificant acreage.

2011 Asset Impairments. Non-cash impairments of unproved properties include $12.2 million related to our East Texas acreage expirations and $2.8 million related to individually insignificant acreage.

2010 Asset Impairments. Following a change in strategic focus from gas to oil-weighted opportunities, we re-allocated our future capital budget. As a result of this change in strategy, we incurred a $22.3 million non-cash impairment expense primarily related to our East Texas acreage.

The following table shows oil and gas property dispositions as of December 31:

	2012	2011	2010
Oil and gas properties	$ —	$ —	$ 2,601,997
Accumulated depreciation, depletion, amortization and impairments	—	—	(1,406,066)
Net oil and gas properties	$ —	$ —	$ 1,195,931

The dispositions of assets resulted in a loss of zero, zero and $1.1 million for 2012, 2011 and 2010, respectively.

We have capitalized zero and $3.5 million, respectively, in exploratory well costs pending determination of proved reserves for periods less than one year at December 31, 2012 and 2011. We have not capitalized exploratory well costs for periods greater than one year at December 31, 2012 and 2011.

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 crude oil, natural gas and interest rate swaps and collars were obtained from financial institutions and adjusted for non-performance risk, 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 test 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. Additionally, we may use appropriate market data to determine fair value. 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 ARO 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.

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) was as follows at December 31, 2012:

	Total Carrying Value	Fair Value Measurements Using		
		Level 1	Level 2	Level 3
Derivatives				
Commodity price contracts	$ 1,960,005	$ —	$ 1,960,005	$ —

Fair value information for financial assets and (liabilities) was as follows at December 31, 2011:

	Total Carrying Value	Fair Value Measurements Using		
		Level 1	Level 2	Level 3
Derivatives				
Commodity price contracts	$ 4,248,194	$ —	$ 4,248,194	$ —

Fair value information for non-financial assets and (liabilities) valued on a non-recurring basis was as follows:

	Carrying Value (1)	Fair Value Measurements Using			Total Pre-tax (Non-cash) Impairment Loss
		Level 1	Level 2	Level 3	
Year Ended December 31, 2012					
Impairment of proved properties	$ 149,515,252	$ —	$ —	$ 35,149,381	$ 114,365,871
Year Ended December 31, 2011					
Impairment of proved properties (2)	—	—	—	—	—
Year Ended December 31, 2010					
Impairment of proved properties	2,320,977	—	—	1,847,872	473,105

(1) Amounts represent carrying value at the time of the assessment.
(2) We did not measure fair value of non-financial assets or liabilities on a non-recurring basis.

We have a policy to timely identify impairment triggers including a quarterly review of material negative changes to commodity price forward curves and production on a field-by-field basis. We performed this review quarterly throughout 2012 and did not identify any impairment triggers. When we prepared our preliminary 2013 capital budget and drilling plan in the fourth quarter of 2012, we identified impairment triggers related to conventional gas assets in South Texas and unconventional gas assets in East Texas. When preparing our preliminary 2013 budget and following a continuous trend of a depressed natural gas and natural gas liquids price environment throughout 2012, and our success in developing our oil inventory in Southeast Texas in the second and third quarters of 2012, we concluded that we will not likely further develop or participate in new wells in certain fields in South Texas for the foreseeable future. Accordingly, we reclassified certain proved undeveloped reserves to unproven reserves and risk-adjusted these reserves accordingly. Additionally, due to a larger industry player's shift in strategic focus in the fourth quarter of the year including suspension of their James Lime activity in East Texas, we determined it was uncertain whether we would develop the James Lime formation in East Texas and risk-adjusted these reserves accordingly.

As a result of a significant decline in natural gas forward curves and our decision, beginning in the fourth quarter of 2012, not to develop liquids-rich formations, we identified impairment indicators for certain of our conventional gas assets in South and East Texas. In accordance with our impairment policy described above, we compared the net book value for these assets to future cash flows and concluded that fair value impairments were required for certain fields. We used income and market approaches to determine the fair value on a field-by-field basis using market prices based on commodity price forward curves and considering proven, probable and possible reserves. We reduced estimated unproved reserve quantities to account for uncertainty associated with those reserves and discounted cash flows using a pre-tax discount rate between 10% and 15%. We believe that these pre-tax discount rates reflect current market valuations for similar properties. We also valued acreage in certain areas using a dollar amount per acre to determine fair value of probable and possible reserves. See Note 4 - "Oil and Gas Properties" for additional detail related to the impairment of proved properties.

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 $2.0 million and $4.2 million at December 31, 2012 and December 31, 2011, respectively. As a result of these agreements, we recorded non-cash unrealized losses for unsettled contracts, of $2.3 million and $6.5 million for the years ended December 31, 2012 and 2010, respectively and a non-cash unrealized gain for unsettled contracts of $0.5 million for the year ended December 31, 2011. 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 crude oil, natural gas and natural gas liquids sales for our commodity price hedges and as an (increase) decrease in interest expense for our interest rate swaps. Our final interest rate swap terminated on May 8, 2011.

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 crude oil, natural gas 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, put options, 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. 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 senior secured 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, 2012:

Crude Oil		Volume/Month	Price/Unit	Fair Value
Jan 2013-Dec 2013	Swap	14,000 Bbls	$101.25 (1)	$ 1,346,343
Jan 2013-Dec 2013	Swap	9,000 Bbls	$109.13 (2)	232,424
Jan 2013-Jun 2013	Swap	6,000 Bbls	$108.35 (2)	(9,626)
Jan 2013-Dec 2013	Swap	6,000 Bbls	$107.10 (2)	9,047
Jan 2013-Mar 2013	Swap	11,000 Bbls	$106.90 (2)	(87,050)
Apr 2013-Jun 2013	Swap	7,000 Bbls	$104.80 (2)	(60,153)
Jul 2013-Sep 2013	Swap	6,000 Bbls	$103.47 (2)	(45,781)
Oct 2013-Dec 2013	Swap	3,000 Bbls	$102.30 (2)	(21,320)
Jan 2014-Dec 2014	Swap	7,500 Bbls	$102.10 (2)	9,304
Natural Gas				
Jan 2013-Jun 2013	Collar	50,000 MMBtu	$3.75 - $4.00 (3)	113,637
Jan 2013-Dec 2013	Collar	75,000 MMBtu	$3.00 - $4.25 (3)	(22,768)
Jan 2013-Dec 2013	Collar	75,000 MMBtu	$3.25 - $4.00 (3)	124
Jan 2013-Dec 2013	Collar	35,000 MMBtu	$3.75 - $4.21 (3)	131,550
Jan 2013-Dec 2014	Collar	42,500 MMBtu	$3.75 - $4.60 (3)	217,794
Jan 2013-Dec 2014	Collar	42,500 MMBtu	$3.50 - $5.00 (3)	146,480
			Total net fair value of derivative instruments	$ 1,960,005

(1) Commodity derivative based on West Texas Intermediate crude oil prices
(2) Commodity derivative based on Brent crude oil prices
(3) Commodity derivative based on Henry Hub NYMEX natural gas prices

We also entered into the following commodity swaps with a counterparty in our bank group on February 8, 2013:

Crude Oil		Volume/Month	Price/Unit
Jan 2014 – Jun 2014	Swap	2,000 Bbls	$108.07 (1)
Jan 2014 – Dec 2014	Swap	6,000 Bbls	$106.40 (1)

(1) Commodity derivative based on Brent crude oil prices

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,		
		2012	2011	2010
Crude oil contracts	Crude oil sales	$ 1,093,148	$ (3,531,207)	$ 1,446,686
Natural gas contracts	Natural gas sales	5,872,660	11,283,031	19,465,873
Natural gas liquids contract	Natural gas liquids sales	—	(254,220)	—
Interest rate contracts	Interest expense	—	(1,410,764)	(4,594,968)
Realized gain		$ 6,965,808	$ 6,086,840	$ 16,317,591
Crude oil contracts	Unrealized (loss) gain on derivative instruments	$ 1,483,337	$ 2,699,354	$ (1,477,423)
Natural gas contracts	Unrealized (loss) gain on derivative instruments	(3,771,526)	(3,637,188)	(8,241,131)
Interest rate contracts	Unrealized (loss) gain on derivative instruments	—	1,392,740	3,217,729
Unrealized gain (loss)		$ (2,288,189)	$ 454,906	$ (6,500,825)

7. Accrued Liabilities

Accrued liabilities consist of the following:

	December 31,	
	2012	2011
Capital drilling and operating costs	$ 4,317,352	$ 12,708,058
Accrued compensation	1,800,000	2,800,000
Interest and loan fees	129,614	82,604
Other	433,877	540,662
Total	$ 6,680,843	$ 16,131,324

8. Asset Retirement Obligations

We estimate the fair values of AROs based on historical experience of plug and abandonment costs and assumptions and judgments regarding factors such as the existence of a legal obligation for an ARO; estimated probabilities, amounts and timing of settlements; the credit-adjusted risk-free rate to be used and inflation rates.

A roll forward of our asset retirement obligation liability is as follows:

	December 31,	
	2012	2011
Balance beginning of year	$ 10,006,769	$ 9,834,021
Accretion expense	495,389	489,077
Liabilities incurred	418,305	87,106
Liabilities settled	(787,745)	(404,594)
Revisions	896,488	1,159
Balance end of year	$ 11,029,206	$ 10,006,769

9. Debt

Revolving Credit Agreement

We maintain a $400.0 million senior secured revolving credit agreement with Wells Fargo Bank, National Association ("*Wells Fargo Bank*"), as agent, and the lender parties thereto (the "*Senior Credit Agreement*") dated as of July 15, 2005, as amended. Since that time, we have amended and restated this agreement as necessary. Our Senior 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 Senior 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 Senior Credit Agreement 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) a ratio of our total debt to Adjusted EBITDAX for any four trailing fiscal quarters not greater than 3.50 to 1.00, (iii) a ratio of Adjusted EBITDAX to cash interest expense for any four trailing fiscal quarters not less than 2.75 to 1.00, and (iv) a ratio of the sum of (a) the aggregate outstanding principal amount borrowed under our Senior Credit Agreement plus (b) the aggregate face amount of all outstanding letters of credit, to EBITDAX for the trailing four fiscal quarters not greater than 2.25 to 1.00. EBITDAX represents net income (loss) before net interest expense, income taxes, and depreciation, depletion, amortization and exploration expenses. Adjusted EBITDAX, as defined in our Senior Credit Agreement, 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 Senior Credit Agreement and second lien credit agreement.

Borrowings under our Senior Credit Agreement are subject to a borrowing base limitation based on our proved crude oil and natural gas reserves. The borrowing base under our Senior Credit Agreement is currently $100.0 million. The next borrowing base redetermination is scheduled for May 1, 2013 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 Senior Credit Agreement also provides for the issuance of letters-of-credit up to a $5.0 million sub-limit. At December 31, 2012, we had $67,600 in letters of credit outstanding and no senior unsecured notes outstanding. All principal amounts, together with all accrued and unpaid interest outstanding under our Senior Credit Agreement will be due and payable in full on May 31, 2015.

Advances under our Senior 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. The applicable margin ranges between 1.75% and 2.75%, for LIBOR loans, and between 0.75% and 1.75%, 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 nine months may be selected. The commitment fee payable on the unused portion of our borrowing base is between 0.375% and 0.500%, depending on the borrowing base utilization.

At December 31, 2012, we had $69.2 million outstanding under our Senior Credit Agreement, with availability of $30.8 million.

Second Lien Credit Agreement

We also maintain a second lien credit agreement, dated December 27, 2010, with Barclays Bank Plc, as agent, and the lender parties thereto, including an affiliate of OCM GW Holdings, LLC ("*Oaktree Holdings*"), our largest stockholder (the "*Second Lien Credit Agreement*") which provided for a term loan, made to us in a single draw, in an aggregate principal amount of $175 million that matures on December 27, 2015. See Note 10 - "Transactions with related parties" for further information.

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 Senior 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 1.50 to 1.00. 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, 2012, we had a principal amount of $175.0 million outstanding under our Second Lien Credit Agreement, with a discount of $4.7 million using the estimated market value interest rate at the time of issuance, for a net balance of $170.3 million.

Summary

At December 31, 2012, we were in compliance with the covenants under our Senior Credit Agreement and Second Lien Credit Agreement.

The Senior Credit Agreement and the Second Lien Credit Agreement (the "*Credit Agreements*") are secured by liens on substantially all of our assets, as well as security interests in the stock of our subsidiaries. The liens securing the Second Lien Credit Agreement are junior to those securing the Senior Credit Agreement. Interest is payable under the Credit Agreements as interim borrowings mature.

Our debt consists of the following:

	December 31, 2012	December 31, 2011
Senior Credit Agreement (weighted average interest rate in effect at December 31, 2012 was 2.76%)	$ 69,102,161	$ 20,977,937
Second Lien Credit Agreement (interest rate in effect at December 31, 2012 was 12.50%)	175,000,000	175,000,000
	244,102,161	195,977,937
Less: Unamortized debt discount	(4,733,296)	(5,936,004)
Total long-term debt	$ 239,368,865	$ 190,041,933

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

	Long-Term Debt
2013	—
2014	—
2015	244,102,161
2016	—
2017	
Total	$ 244,102,161

10. Transactions with related parties

As discussed in Note 9 - "Debt", one of the lenders in our Second Lien Credit Agreement is an affiliate of Oaktree Holdings, our largest stockholder. The terms and conditions of the Second Lien Credit Agreement are identical for all lenders, including Oaktree Holdings.

11. Commitments and Contingencies

Lease Obligations

We currently lease and sublease, through January 31, 2019, corporate office space located at 717 Texas Avenue in downtown Houston, Texas. Total general and administrative rent expense for the years ended December 31, 2012, 2011 and 2010, was approximately $2.4 million, $1.3 million and $1.1 million, respectively. On January 1, 2013 we subleased 27,144 square feet of this space to a third party for a total rental of approximately $85,000 per month through January 31, 2014. The sublease rent will be accounted for as a reduction to rent expense. We recorded an onerous contract liability of $0.3 million as of December 31, 2012 related to this sublease. We have entered into various vehicle leases for periods ranging from 12 to 24 months. These contracts will expire at various times. We also have various other equipment leases. Total operational rent expense for the years ended December 31, 2012, 2011 and 2010, were approximately $2.4 million, $2.4 million and $2.3 million, respectively.

The following table provides information about our total operating lease obligations as of December 31, 2012:

		Operating leases (1)
2013	$	2,301,131
2014		1,050,151
2015		947,916
2016		961,813
2017		975,711
Thereafter		1,237,878
Total	$	7,474,600

(1) Operating leases include contracts related to office space, compressors, vehicles, office equipment and other. Operating lease commitments exclude a sublease of office space that is expected to reduce operating lease expense in 2013 and 2014 by approximately $1.0 million and $85,000, respectively

Legal Proceedings

From time to time, we are involved in legal proceedings relating to claims relating to our properties or operations or business or arising from disputes with vendors in the normal course of business.

Mineral interest owners in East Texas filed two causes of action against us on May 26, 2009 and August 26, 2009, respectively, in the District Court for San Augustine County in Texas alleging breach of contract for not paying lease bonuses on certain prospective oil and gas leases that were pursued by our leasing agent but never taken by Crimson. These cases were settled in January 2013 for an immaterial amount.

The holders of oil and gas leases in South Louisiana filed suit against Crimson and several co-defendants in June 2009 in the 31st Judicial District Court situated in Jefferson Davis Parish, Louisiana alleging failure to act as a reasonably prudent operator, failure to explore, waste, breach of contract, etc. in connection with two wells located in Jefferson Davis Parish. Many of the alleged improprieties occurred prior to our ownership of an interest in the wells at issue, although we may have assumed liability otherwise attributable to our predecessors-in-interest through the acquisition documents relating to the acquisition of our interest in these wells. The damages most-recently alleged by the plaintiffs are approximately $13.4 million. We and our co-defendants are vigorously defending this lawsuit and believe that we have meritorious defenses. We do not believe this suit 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, Crimson, several predecessor operators and several product purchasers were named in a lawsuit filed in the District Court for Lavaca County in Texas by an entity alleging that it owns a working interest in a productive formation that has not been recognized by us or 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 trial court recently granted the plaintiffs motion for partial summary judgment as to liability. We are reviewing our potential exposure associated with this case and estimate that the maximum amount of damages that could be asserted by the plaintiffs is $4.9 million, exclusive of interest and legal fees which may be recoverable by the plaintiff if it ultimately prevails in this case. We are vigorously defending this lawsuit, believe that we have meritorious defenses and intend to appeal the aforementioned decision. 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.

In September 2012, we were named as defendant in a lawsuit filed in district court for Harris County in Texas involving a title dispute over a 1/16th mineral interest in the producing intervals of certain wells operated by us in the Catherine Henderson "A" Unit in Liberty County in Texas. The plaintiff has alleged that, based on its interpretation of a series of 1972 deeds, it owns a 1/16th unleased mineral interest in the producing intervals of these wells on which it has not been paid (this claimed interest is in addition to a 1/16th unleased mineral interest on which it has been paid). We have made royalty payments with respect to the disputed interest in reliance, in part, upon leases obtained from successors to the grantors under the aforementioned deeds, who claim to have retained the disputed mineral interests thereunder, and we have intervened in a lawsuit regarding the disputed interest filed by these successors in the District Court for Liberty County. The plaintiff alleges damages in excess of $6.0 million, which is based on prior payments received on its undisputed 1/16th mineral interest. This case remains in its early stages and we are assessing the plaintiff's claims and issues associated therewith, but we intend to vigorously defend this lawsuit. We believe if this matter were to be determined adversely, amounts owed to the plaintiff could be partially offset by recoupment rights we may have against other working interest and/or royalty interest owners in the unit. We do not believe this suit 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.

While many of these matters involve inherent uncertainty and we are unable at the date of this report to estimate an amount of possible loss with respect to certain of these matters, we believe that the amount of the liability, if any, ultimately incurred with respect to these proceedings or claims will not have a material adverse effect on our consolidated financial position as a whole or on our liquidity, capital resources or future annual results of operations.

Employment Agreements

In June 2011, 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 $450,000 and $365,000, 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 June 2011, we entered into amended and restated employment agreements with two other Senior Vice Presidents. 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 $220,000 to $230,000, 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's annual cash incentive bonus, health insurance benefits for 24 months and acceleration to 100% vested status for all stock, stock option and other equity awards.

In April 2012, we entered into an amended and restated employment agreement with one 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 annual base salary of $240,000 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's annual cash incentive bonus, health insurance benefits for 24 months and acceleration to 100% vested status for all stock, stock option and other equity awards.

12. Share-Based Compensation

As of December 31, 2012, 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 as part of their compensation package.

Incentive Plans

We provide performance-based long-term bonus plans 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 under those plans are approved by the Compensation Committee. Upon achieving the performance levels established each year, bonus awards are calculated as a percentage of base salary for the plan year. The plan awards for each year are disbursed in the first quarter of the following year. Employees must be employed by us at the time that final plan awards are dispersed to be eligible.

The CIBP awards are paid out in cash (*"Cash Awards"*). The performance targets are evaluated on a quarterly basis and used to estimate the approximate expense earned to date for each year. Approximately $1.2 million, $2.8 million and $2.9 million were recognized as compensation expense related to the Cash Awards for the twelve months ended December 31, 2012, 2011 and 2010, respectively and were paid in March 2013, 2012 and 2011, respectively.

The LTIP bonus awards can be paid in either restricted Common Stock or 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 are determined based upon the fair market value of the Common Stock on the date of the grant. The fair value of the stock options to be awarded as part of this plan is determined through use of the Black-Scholes valuation model. The Stock Awards granted pursuant to this plan are granted under the existing amended and restated 2005 Stock Incentive Plan.

Due to the decline in our stock price, the Board of Directors suspended the LTIP in 2009. The LTIP has not yet been reinstated. However at the Board of Directors' discretion, bonus awards may be made in the form of restricted stock or stock options.

Stock Options

We maintain a 2005 Stock Incentive Plan (*"2005 Plan"*) and authorized the issuance of up to approximately 5.8 million shares of Common Stock pursuant to awards under the plan. In 2007, we also issued 250,000 shares of restricted Common Stock to our executive officers outside of these plans. Approximately 1.7 million (0.5 million vested) stock options and 1.8 million unvested restricted shares were outstanding at December 31, 2012. Option awards outstanding have exercise prices ranging from $2.13 to $5.00 per share. In 2012 and 2011, respectively, 393,127 and 354,051 shares of restricted Common Stock vested, of which 53,826 and 46,215 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, 2012, we had approximately 1.1 million shares of Common Stock available for future grant under the 2005 Plan.

For stock options, we recorded $0.5 million, $0.6 million and $0.3 million in expense (included on the Consolidated Statements of Operations in general and administrative expense) for the years ended December 31, 2012, 2011 and 2010, respectively, and an estimated $0.8 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.

	2012	**2011**	**2010**
Weighted average fair value of awards	$ 2.16	$ 2.07	$ 2.19
Pre-vest forfeiture rate	7.36%	6.92%	5.01%
Average grant price	$ 3.23	$ 3.35	$ 3.19
Expected volatility	74.68%	74.47%	75.38%
Risk-free rate	1.13%	1.65%	2.55%
Expected dividend yields	None	None	None
Expected term (in years)	6.40	6.34	6.36

The following table summarizes stock option activity for the three years ended December 31, 2012:

	Number of Shares Underlying Options	Weighted Average Exercise Price	Intrinsic Value
Outstanding at December 31, 2010	1,741,543	8.84	$ 700,174
Granted	1,453,240	4.79	—
Exercised	(25,036)	2.42	$ 17,251
Cancelled/forfeited	(1,454,389)	10.20	$ 42,039
Outstanding at December 31, 2011	1,715,358	4.35	$ 114,189
Granted	34,500	3.23	—
Exercised	(15,463)	2.43	$ 30,745
Cancelled/forfeited	(58,976)	3.89	$ 65,302
Outstanding at December 31, 2012	1,675,419	4.36	$ 69,712
Exercisable at December 31, 2012	522,870	4.01	$ 48,425

Restricted Stock Awards

For restricted stock awards, we recorded $2.0 million, $1.4 million and $1.5 million in expense (included on the Consolidated Statements of Operations in general and administrative expense) for the years ended December 31, 2012, 2011 and 2010, respectively and an estimated $3.6 million will be expensed over the remaining vesting period.

In 2012, we issued 959,000 shares of unvested Common Stock, pursuant to restricted stock awards under the 2005 Stock Plan to employees, of which 33,500 were subsequently forfeited. The restricted stock will vest over a four year period. We also issued 54,879 shares of Common Stock pursuant to restricted stock awards to three 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 $3.3 million on the grant date and will be amortized over the vesting period.

In 2011, we issued 446,725 shares of unvested Common Stock, pursuant to restricted stock awards under the 2005 Stock Plan, of which 43,020 were subsequently forfeited. The restricted stock will vest over a four year period. We also issued 39,267 shares of Common Stock pursuant to restricted stock awards to three 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 $1.8 million on the grant date and will be amortized over the vesting period.

In 2010, we issued 402,859 shares of unvested Common Stock, pursuant to restricted stock awards under the 2005 Stock Plan, 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.

Restricted stock activity for the three years ended December 31, 2012 is summarized below:

	Shares	Weighted-Average Grant Date Fair Value
Non-vested as of December 31, 2010	1,268,037	$3.28
Granted	485,992	3.78
Vested	(354,051)	3.48
Cancelled/forfeited	(192,665)	3.70
Non-vested as of December 31, 2011	1,207,313	3.36
Granted	1,013,879	3.26
Vested	(393,127)	3.23
Cancelled/forfeited	(43,601)	3.23
Non-vested as of December 31, 2012	1,784,464	$3.33

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

Subsequent Event

During the first quarter 2013, we issued restricted stock awards for 632,000 shares of Common Stock to employees. As a result, we have 515,380 shares available to be awarded pursuant to 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:

	2012	2011	2010
Net loss	$(91,991,355)	$(15,845,382)	$(30,844,897)
Weighted-average number of shares of Common Stock – basic	44,147,787	44,788,551	39,397,486
Loss per share - basic	$ (2.08)	$ (0.35)	$ (0.78)
Weighted-average number of shares of Common Stock – diluted	44,147,787	44,788,551	39,397,486
Loss per share – diluted	$ (2.08)	$ (0.35)	$ (0.78)

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

Potential dilutive securities (stock options, stock warrants and convertible preferred stock) have not been considered since we reported a net loss and, accordingly, their effects would be antidilutive. The potentially dilutive shares would have been 560,469 shares, 82,634 shares and 95,967 shares in 2012, 2011 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:

	2012	2011	2010
Liabilities released on property dispositions	$ —	$ —	$ 351,092

15. Income Taxes

Income tax benefit for 2012, 2011 and 2010 consist of the following:

	2012	2011	2010
Current tax expense	$ 343,252	$ —	$ —
Deferred tax benefit	(35,062,841)	(8,098,357)	(16,607,139)
Income tax benefit	$ (34,719,589)	$ (8,098,357)	$ (16,607,139)

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, 2012, 2011 and 2010, respectively:

	2012	2011	2010
Loss before income taxes	$ (126,710,944)	$ (23,943,739)	$ (47,452,036)
Income tax benefit at statutory rate	$ 44,348,830	$ 8,380,309	$ 16,608,213
Valuation allowance	(10,197,845)	—	—
Adjustment to NOL carryforward	—	—	(261,154)
Effect for permanent items	(11,496)	(17,306)	(23,699)
State taxes and other	580,100	(264,646)	283,779
Income tax benefit	$ 34,719,589	$ 8,098,357	$ 16,607,139

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

	December 31, 2012	December 31, 2011
Deferred tax assets		
Net operating loss carryforwards	$ 38,988,438	$ 59,443,480
Oil and gas properties	19,163,931	—
Deferred compensation	8,057,657	7,177,942
Income tax credits	347,737	281,424
Deferred tax assets before valuation allowance	66,557,763	66,902,846
Valuation allowance	(13,290,201)	(3,238,656)
Net deferred tax assets	53,267,562	63,664,190
Deferred tax liabilities		
Oil and gas properties	—	(44,780,151)
Derivative instruments	(532,795)	(1,349,679)
Other	(563,451)	(425,726)
Deferred tax liabilities	(1,096,246)	(46,555,556)
Net deferred tax assets	$ 52,171,316	$ 17,108,634

As of December 31, 2012, we had federal and state net operating loss ("*NOL*") carryforwards of approximately $110.7 million and $6.8 million, respectively, which are available to reduce future taxable income and the related income tax liability. We have a total valuation allowance against federal NOL carryforwards totaling $38.0 million, or $13.3 million tax-adjusted at the federal statutory rate, consisting of two parts. In prior years, we recorded a full valuation allowance against approximately $8.8 million, or $3.1 million tax-adjusted, against NOL carryforwards that we will not be able to utilize due to the limitations of Internal Revenue Code Section 382 ("Section 382"). In the fourth quarter of 2012, we recorded a partial valuation allowance of approximately $29.1 million, or $10.2 million tax-adjusted, against NOL carryforwards that are not impacted by limitations of Section 382 as discussed below.

The combination of significant taxable losses in recent years, lower than budgeted taxable income for the fourth quarter of 2012 and our preliminary budget for 2013, do not allow us to significantly reduce NOL carryforwards in 2012 or 2013 resulting in a material amount of NOL carryforwards. Following the before mentioned events in the fourth quarter of 2012, we concluded that a partial valuation allowance against NOL carryforwards was required. To estimate the amount of NOL carryforwards we can utilize more likely than not within the carryforward period, we projected future taxable income and applied a risk factor to the outer years. Following this methodology, we increased the tax-adjusted valuation allowance against NOL carryforwards by $29.1 million, or $10.2 million tax adjusted.

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 $13.3 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.

Federal NOL carryforwards of $110.7 million expire at various dates beginning in 2013 and ending in 2033. NOL carryforwards of $8.8 million impacted by Section 382 limitations will expire between 2013 and 2016. NOL carryforwards of $101.9 million, associated with losses incurred in recent years and not impacted by Section 382 limitations, expire at various dates beginning in 2026 and ending in 2033. We continue to believe that we will be able to utilize the majority of the NOL carryforwards that are not impacted by Section 382 before they expire. Depending on taxable income in future years, we could increase or decrease the valuation allowance.

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, 2011	$	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, 2012	$	518,219

Generally, our income tax years of 2008 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, 2012 and 2011, 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, 2012. 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. Disclosure of Major Customers

For the years ended December 31, 2012, 2011 and 2010, there were four customers who accounted for more than 10% of revenues:

	2012	2011	2010
Sunoco, Inc.	$ 34,147,610	$ 22,579,414	$ 10,951,458
Valero Marketing & Supply Co.	22,321,999	— (1)	— (1)
DCP Midstream, LP	15,412,128	31,727,341	23,224,023
Shell Trading (U.S.) Company	11,692,738	— (1)	— (1)

(1) Customer represented less than 10% of revenues for the years ended December 31, 2011 and 2010.

Each of our major customers represents a significant percentage of total revenue. Contracts with our major customers are short-term or evergreen contracts based on prevailing commodity market prices at the time of delivery. A change in one or all of our major customers, whether initiated by the customer or by us, is unlikely to have a significant interruption in production or revenue.

17. Quarterly Results (Unaudited)

Summary data relating to the results of operations for each quarter for the years ended December 31, 2012 and 2011 follows:

	Three Months Ended			
	March 31	June 30	September 30	December 31
2012				
Net revenues	$ 26,686,579	$ 30,524,011	$ 30,770,456	$ 27,922,970
Income (loss) from operations	438,664	9,353,398	5,985,397	(114,228,048)
Net income (loss)	(4,399,085)	3,910,819	(3,846,124)	(87,656,965)
Income(loss)per common share (1)				
Basic	$ (0.10)	$ 0.09	$ (0.09)	$ (1.98)
Diluted	$ (0.10)	$ 0.09	$ (0.09)	$ (1.98)
Weighted average shares outstanding				
Basic	43,976,950	44,134,330	44,208,471	44,269,388
Diluted	43,976,950	44,992,883	44,208,471	44,269,388
2011				
Net revenues	$ 27,622,019	$ 29,664,706	$ 28,914,071	$ 27,435,237
Income (loss) from operations	(1,474,685)	349,489	3,083,102	380,692
Net income (loss)	(8,545,962)	(2,826,563)	526,600	(4,999,457)
Income(loss)per common share (1)				
Basic	$ (0.19)	$ (0.06)	$ 0.01	$ (0.11)
Diluted	$ (0.19)	$ (0.06)	$ 0.01	$ (0.11)
Weighted average shares outstanding				
Basic	44,939,828	45,188,542	45,121,172	43,904,661
Diluted	44,939,828	45,188,542	45,166,566	43,904,661

(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.

18. 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 NSAI. 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 for that year 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.

Proved Oil and Gas Reserve Quantities

The following table sets forth net proved crude oil, natural gas and natural gas liquids reserves, all within the United States, at December 31, 2012, 2011 and 2010, together with the changes therein.

	Crude Oil (MBbls)	Natural Gas (MMcf)	Natural Gas Liquids (MBbls)	Total (Mcfe)
QUANTITIES OF PROVED RESERVES:				
Balance December 31, 2010	2,164	135,675	2,973	166,498
Revisions [1]	2	(18,645)	(165)	(19,625)
Extensions, discoveries and additions	1,943	57,311	154	69,890
Sales [2]	22	35	—	170
Production	(397)	(11,676)	(418)	(16,564)
Balance December 31, 2011	3,734	162,700	2,544	200,369
Revisions [1]	134	(98,683)	189	(96,738)
Extensions, discoveries and additions	3,088	5,666	559	27,544
Sales [2]	—	—	—	—
Production	(754)	(7,799)	(300)	(14,126)
Balance December 31, 2012	6,202	61,884	2,992	117,049
PROVED DEVELOPED RESERVES:				
December 31, 2010	1,403	60,325	1,898	80,130
December 31, 2011	1,845	53,024	1,637	73,913
December 31, 2012	2,343	39,554	1,686	63,732
PROVED UNDEVELOPED RESERVES:				
December 31, 2010	761	75,350	1,075	86,368
December 31, 2011	1,890	109,676	907	126,456
December 31, 2012	3,859	22,330	1,306	53,317

(1) 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.
(2) Sales are calculated based on the beginning of the year reserves adjusted for current year production with no adjustment for revisions.

Capitalized Costs Relating to Oil and Gas Producing Activities

	2012	2011
Unproved oil and gas properties	$ 14,016,656	$ 17,799,420
Proved oil and gas properties	662,277,626	592,699,504
Wells and related equipment and facilities	63,775,863	52,915,523
	740,070,145	663,414,447
Less accumulated depreciation, depletion, amortization and impairment	(439,829,372)	(267,614,210)
Net capitalized costs	$ 300,240,773	$ 395,800,237

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, 2012:

	2012	2011	2010
Property Acquisitions:			
Proved	$ —	$ 1,101,868	$ —
Unproved	1,724,053	8,221,361	5,774,043
Development Costs	68,636,057	69,595,880	47,973,323
Exploration Costs	10,139,041	10,199,440	2,000,941
Total	$ 80,499,151	$ 89,118,549	$ 55,748,307

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.

Results of Operations for Oil and Natural Gas Producing Activities

The following table shows the results of operations for oil and natural gas producing activities for the years ended December 31, 2012, 2011 and 2010, respectively:

	2012	2011	2010
Oil, natural gas and natural gas liquids sales	$ 108,938,208	$ 106,138,430	$ 75,019,664
Production costs	18,055,355	21,001,717	22,030,309
Depreciation, depletion and amortization	58,764,443	56,920,515	45,022,272
Impairment and abandonment of oil and gas properties	117,890,239	14,954,633	22,254,059
Income (loss) before income taxes	(85,771,829)	13,261,565	(14,286,976)
Income tax benefit (expense)	23,502,016	(4,485,385)	5,000,118
Results of operations	$ (62,269,813)	$ 8,776,180	$ (9,286,858)

Sales are based on market prices and exclude the effects of realized derivative hedging gains of $7.0 million, $7.5 million and $20.9 million for the years 2012, 2011 and 2010, respectively. The results of operations for oil and natural gas producing activities exclude general and administrative expenses, interest and other financing charges, gain on sale of assets and the effects of unrealized derivative hedging gains and losses.

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 (*"Standardized Measure"*) 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, 2010, the future pretax net cash flows from our proved oil and gas reserves were estimated to be less than the sum of the tax basis of the applicable producing properties and our available NOL carryforwards; therefore, there was zero future tax benefit or expense at December 31, 2010. We believe it is more likely than not that all of our total available NOL carryforwards will be realized within the appropriate carryforward period. Our operations and all NOL carryforwards 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 is not required to be presented for interim financial presentation dates.

Standardized Measure relating to proved reserves:

	2012	2011	2010
Future cash inflows	$ 895,951,200	$ 1,133,153,500	$ 860,655,250
Future production and development costs:			
Production	(193,747,800)	(305,301,493)	(218,221,203)
Development	(155,937,800)	(299,390,312)	(195,819,078)
Future cash flows before income taxes	546,265,600	528,461,695	446,614,969
Future income taxes	(80,702,813)	(40,347,466)	(37,624,289)
Future net cash flows after income taxes	465,562,787	488,114,229	408,990,680
10% annual discount for estimated timing of cash flows	(169,123,190)	(232,782,186)	(182,476,004)
Standardized measure of discounted future net cash flows	$ 296,439,597	$ 255,332,043	$ 226,514,676

Our calculations of the Standardized Measure include the effect of estimated future income tax expenses for all years reported. At December 31, 2010, 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 NOL carryforwards; therefore, there was zero future tax benefit or expense at December 31, 2010. We believe it is more likely than not that all of our total available NOL carryforwards will be realized within the appropriate carryforward period. Our operations and all NOL carryforwards are attributable to our oil and gas assets.

The following reconciles the change in the Standardized Measure:

	2012	2011	2010
Beginning of year	$ 255,332,043	$ 226,514,676	$ 176,422,700
Changes from:			
Change in prices and in production costs	61,122,312	35,843,018	(1,102,871)
Changes in estimated future development costs	(1,336,336)	(11,283,184)	(11,801,896)
Sales of crude oil, natural gas and natural gas liquids produced, net of production costs	(91,175,504)	(86,132,123)	(53,956,677)
Extensions, discoveries and improved recovery, less related costs	98,539,507	113,088,953	109,361,697
Purchases of minerals in place	—	226,395	—
Sales of minerals in place	—	—	(408,190)
Revision of quantity estimates	(52,958,824)	(29,416,407)	9,476,255
Previously estimated development costs incurred during the period	22,482,000	75,258,100	11,788,100
Accretion of discount	24,482,116	(70,061,524)	17,642,270
Changes in production rates (timing) and other	12,448,329	(770,619)	(17,700,497)
Change in income taxes	(32,496,046)	2,064,758	(13,206,215)
Total change in the Standardized Measure	41,107,554	28,817,367	50,091,976
End of year	$ 296,439,597	$ 255,332,043	$ 226,514,676

This disclosure excludes the effects of realized hedges ($6,965,808 gain in 2012; $7,497,604 gain in 2011, $20,912,559 gain in 2010) which are included in crude oil and natural gas sales on the Statements of Operations.

CRIMSON EXPLORATION INC. AND SUBSIDIARIES
SCHEDULE II – VALUATION AND QUALIFYING ACCOUNTS
FOR THE YEARS ENDED DECEMBER 31, 2012, 2011 AND 2010

DESCRIPTION	BALANCE AT BEGINNING OF PERIOD	PROVISIONS/ ADDITIONS	RECOVERIES/ DEDUCTIONS	BALANCE AT END OF PERIOD
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
For the year ended December 31, 2011:				
Allowance for doubtful accounts	$ 579,143	60,057	(59,612)	$ 579,588
Valuation allowance for deferred tax assets	$ 3,387,923	—	(149,267)	$ 3,238,656
For the year ended December 31, 2012:				
Allowance for doubtful accounts	$ 579,588	104,386	(158,418)	$ 525,556
Valuation allowance for deferred tax assets	$ 3,238,656	10,197,845	(146,300)	$ 13,290,201