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, 2011

Commission File Number 000-29187-87

Carrizo Oil & Gas, Inc.

(Exact name of registrant as specified in its charter)

Texas	**76-0415919**
(State or other jurisdiction of incorporation or organization)	**(I.R.S. Employer Identification No.)**
500 Dallas Street, Suite 2300, Houston, Texas	**77002**
(Principal executive offices)	**(Zip Code)**

Registrant s telephone number, including area code: (713) 328-1000

Securities Registered Pursuant to Section 12(b) of the Act:

Common Stock, $0.01 par value

Indicate by check mark if the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act. YES þ 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 þ

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 þ NO ¨

Indicate by check mark whether the registrant has submitted electronically and posted on its corporate Web site, 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 þ

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 the definitions of large accelerated filer, accelerated filer and smaller reporting company in Rule 12b-2 of the Exchange Act. (Check one):

Large accelerated filer	þ	Accelerated filer	¨
Non-accelerated filer	¨ (Do not check if a 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 Act). YES ¨ NO þ

At June 30, 2011, the aggregate market value of the registrant s Common Stock held by non-affiliates of the registrant was approximately $1,504 million based on the closing price of such stock on such date of $41.75.

At February 27, 2012, the number of shares outstanding of the registrant s Common Stock was 39,578,464.

DOCUMENTS INCORPORATED BY REFERENCE

Portions of the definitive proxy statement for the Registrant s 2012 Annual Meeting of Shareholders are incorporated by reference in Part III of this Form 10-K. Such definitive proxy statement will be filed with the Securities and Exchange Commission not later than 120 days subsequent to December 31, 2011.

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Forward-Looking Statements.

This annual report contains statements concerning our expectations, beliefs, plans, objectives, goals, strategies, future events or performance and underlying assumptions and other statements that are not historical facts. These statements are forward-looking statements within the meaning of the Private Securities Litigation Reform Act of 1995. These forward-looking statements include, among others, statements regarding:

- our growth strategies;
- our ability to explore for and develop oil and gas resources successfully and economically;
- our estimates of the timing and number of wells we expect to drill and other exploration activities;
- our estimates regarding timing and levels of production;
- anticipated trends in our business;
- the effects of competition on us;
- our future results of operations;
- our liquidity and our ability to finance our exploration and development activities;
- our capital expenditure plan;
- plans regarding our North Sea assets;
- future market conditions in the oil and gas industry;
- our ability to make, integrate and develop acquisitions; and
- the impact of governmental regulation, taxes, market changes and world events.

You generally can identify our forward-looking statements by the words anticipate, believe, budgeted, continue, could, estimate, forecast, goal, intend, may, objective, plan, potential, predict, projection, scheduled, should, or other similar words. Su risks and uncertainties, including, but not limited to, those relating to the worldwide economic downturn, availability of financing, our dependence on our exploratory drilling activities, the volatility of and changes in oil and gas prices, the need to replace reserves depleted by production, operating risks of oil and gas operations, our dependence on our key personnel, factors that affect our ability to manage our growth and achieve our business strategy, results, delays and uncertainties that may be encountered in drilling, development or production, interpretations and impact of oil and gas reserve estimation and disclosure requirements, activities and approvals of our partners and parties with whom we have alliances, technological changes, capital requirements, borrowing base determinations and availability under our credit facilities, evaluations of us by lenders under our credit facilities, the potential impact of government regulations, including current and proposed legislation and regulations related to hydraulic fracturing, oil and natural gas drilling, air emissions and climate change, regulatory determinations, litigation, competition, the uncertainty of reserve information and future net revenue estimates, property acquisition risks, availability of equipment and crews, actions by our midstream and other industry partners, weather, availability of financing, actions by lenders, our ability to obtain permits and licenses, the results of audits and assessments, the failure to obtain certain bank and lease consents, the existence and resolution of title defects, new taxes and impact fees, delays, costs and difficulties relating to our joint ventures, actions by joint venture partners, results of exploration activities, the availability and completion of land acquisitions, completion and connection of wells, and other factors detailed in this annual report.

We have based our forward-looking statements on our management s beliefs and assumptions based on information available to our management at the time the statements are made. We caution you that assumptions, beliefs, expectations, intentions and projections about future events may and often do vary materially from actual results. Therefore, we cannot assure you that actual results will not differ materially from those expressed or implied by our forward-looking statements.

Some of the factors that could cause actual results to differ from those expressed or implied in forward-looking statements are described under Part II, Item 1A. Risk Factors and in other sections of this annual report. Should one or more of these risks or uncertainties materialize, or should underlying assumptions prove incorrect, actual outcomes may vary materially from those indicated. All subsequent written and oral forward-looking statements attributable to us or persons acting on our behalf are expressly qualified in their entirety by reference to these risks and uncertainties. You should not place undue reliance on our forward-looking statements. Each forward-looking statement speaks only as of the date of the particular statement, and, except as required by law, we undertake no duty to update or revise any forward-looking statement.

Certain terms used herein relating to the oil and gas industry are defined in Glossary of Certain Industry Terms.

PART I

Item 1. Business

OVERVIEW

General

Carrizo Oil & Gas, Inc. is a Houston-based independent energy company which, together with its subsidiaries (collectively, Carrizo, the Company or we), is actively engaged in the exploration, development, and production of oil and gas in the United States and United Kingdom. Our current operations are principally focused in proven, producing oil and gas plays primarily in the Eagle Ford Shale in South Texas, the Niobrara Formation in Colorado, the Barnett Shale in North Texas, the Marcellus Shale in Pennsylvania, New York and West Virginia, the Utica Shale in Ohio and Pennsylvania, and the U.K. North Sea where our Huntington Field development project is currently under development.

Since we began focusing a significant portion of our efforts in shale plays, particularly in the Barnett Shale and Eagle Ford Shale, we have grown our reserves at a compounded annual growth rate (CAGR) of 38%, while simultaneously maintaining a CAGR on our production of 25%. During 2011, we added, net of production, 140 Bcfe to proved reserves, for a reserve replacement ratio of 311%. Please read Oil and Gas Reserve Replacement for more information on our reserve replacement ratio. This reserve replacement ratio was achieved in spite of record production in 2011 of 45.1 Bcfe, a 22% increase from 2010. At year-end 2011, our proved reserves of 936 Bcfe were approximately 22% crude oil, condensate and natural gas liquids and approximately 78% natural gas, as compared to 20% and 80% at year-end 2010, respectively.

The following table provides details about the Company s proved reserves.

	Proved Reserves (Bcfe)	
	December 31, 2011	**December 31, 2010**
Barnett Shale	658	680
Eagle Ford Shale	171	90
U.K. North Sea	38	36
Marcellus Shale	37	3
Gulf Coast/Camp Hill	26	30
Niobrara Formation	6	2
Total	936	841

Our Board of Directors has approved a U.S. capital expenditure plan of $465 million for 2012. This plan reflects our strategy of controlling capital costs and maintaining financial flexibility in light of current economic conditions and is comparable to our $492 million capital expenditures in 2011. We currently expect to commit the majority of our 2012 U.S. capital expenditure plan to the continued development of our properties in the Eagle Ford Shale, Niobrara Formation, and the Marcellus Shale . The level of our expected Marcellus Shale and Eagle Ford Shale capital expenditures has been decreased by the obligation of our joint venture partner to carry a portion of our costs. In the U.K., we have entered into a limited recourse project financing arrangement which we expect to fund all of our $35.0 million capital expenditures plan for our Huntington Field development project in the U.K. North Sea in 2012. We intend to finance our 2012 U.S. capital expenditure plan primarily from cash flow from operations, our senior secured credit facility in the U.S., and our secured limited recourse facility in the U.K. Other available sources of funding include proceeds from the possible selective sale of non-core assets, offerings of securities and joint ventures where partners are required to carry a portion of our capital costs.

The table below highlights our primary areas of activity:

	Capital Expenditures ($ in millions)	
	2012 Plan	2011 Actual
Eagle Ford Shale	$ 320	$ 195
Marcellus Shale	62	47
Niobrara Formation	43	39
Barnett Shale	15	100
U.S. drilling capital expenditures	440	381
U.S. leasehold, seismic, and other project areas	25	111
Total U.S. capital expenditures	465	492
U.K. North Sea	35	39
Total	$ 500	$ 531

Crude Oil and Liquids Plays and Projects

At December 31, 2011, our crude oil and liquids proved reserves were 34.7 MMBOE, a 22% increase from 28.5 MMBOE at December 31, 2010. The significant increase in crude oil and liquids reserves was due to the execution of our new growth strategy in crude oil and liquids-rich plays in the Eagle Ford Shale and the Niobrara Formation, collectively adding 14.4 MMBOE of crude oil and liquids to our proved reserves (14.2 MMBOE including associated gas) during 2011, which was partially offset by the sale of a substantial portion of the non-core area Barnett Shale properties (8 MMBOE of crude oil and liquids reserves as of December 31, 2010).

Eagle Ford Shale

Following the April 2010 announcement of our growth strategy to increase crude oil and liquids production, we commenced a leasing program targeting the gas condensate window of the Eagle Ford Shale. As of December 31, 2011, we held interests in approximately 98,127 gross (41,044 net) acres, 23 gross (19.5 net) producing wells and 12 gross (9.2 net) wells that were drilled but waiting on completion and/or pipeline connection. Of these wells, we operated 23 gross (19.5 net) producing wells and 12 gross (9.2 net) wells drilled and waiting on completion and/or pipeline connection. During 2011, we drilled 30 gross wells (23 net), all of which we operated, and completed and brought on production 18 gross wells (13.9 net). Approximately 16% of our 98,127 gross acres in the Eagle Ford Shale is either in currently designated producing units or in units on which wells have been drilled and are waiting on completion and/or pipeline connection. Our 2011 production in the Eagle Ford Shale was 644 MBOE (1,764 Bbls/d), 1,533% above 2010 production of 39 MBOE (108 Bbls/d). Total proved reserves for the Eagle Ford Shale were 28 MMBOE at December 31, 2011, approximately 86%, or 24 MBOE, of which was crude oil and liquids.

As of December 31, 2011, we were operating four rigs in the Eagle Ford Shale and expect to release one rig in March 2012 and then operate the remaining rigs in the Eagle Ford Shale throughout 2012. We currently expect our 2012 Eagle Ford Shale drilling efforts to require an investment of approximately $320 million for drilling and completion costs, which will be spent primarily in our core area within the Eagle Ford Shale in LaSalle county and, to a lesser extent, in McMullen and Atascosa counties.

Although we experienced an increase in completion costs due to increased demand for hydraulic fracturing crews during 2011, we have seen moderation in these costs in early 2012 as a result of the availability of new pressure pumping equipment and the reduced completion activity in resource plays producing primarily natural gas.

GAIL Joint Venture

In September 2011, we completed the sale of 20% of our interests in certain oil and gas properties in the Eagle Ford Shale (comprising approximately 4,040 net acres, including 5.9 net wells that were producing on these properties at the effective time of the sale) to GAIL GLOBAL (USA) INC. (GAIL), a wholly-owned subsidiary of GAIL (India) Limited, for $63.7 million in cash and a commitment by GAIL to pay a development carry of 50% of certain of our future development costs up to approximately $31.3 million net to our interest as further described below. In connection with this sale transaction, we and GAIL also entered into agreements to form a new joint venture with respect to the interests purchased by GAIL. Under the terms of the agreement, we generally retained a 80% working interest in the acreage and GAIL owns a 20% working interest. The GAIL development carry lasts until June 30, 2013, unless earlier utilized. We currently expect the GAIL development carry to be exhausted in the first quarter of 2012.

We have also granted an option in favor of GAIL to purchase a 20% share of acreage acquired by us after the closing located in specified areas adjacent to the initially purchased areas. This option is exercisable at our cost plus, in the case of direct property sales, a specified premium, and is subject to specified exceptions. We serve as operator of the properties covered by this joint venture. Through December 31, 2011, GAIL had exercised option to increase its acreage position by approximately 208 net acres.

Niobrara Formation

As part of our growth strategy in crude oil and liquids, starting in 2010, we also acquired working interests in the Niobrara Formation located in the Denver-Julesberg Basin in Weld and Morgan counties, Colorado. During 2011, we drilled 8 gross wells (4.7 net), of which we operated 7 gross wells (4.4 net), and completed and brought on production 7 gross wells (4.1 net). As of December 31, 2011, we held interests in approximately 107,552 gross (58,255 net) acres, 9 gross (7.6 net) producing wells and 1 gross (0.6 net) wells that were drilled but waiting on completion and/or pipeline connection. Of these wells, we operated 8 gross (6.82 net) producing wells and 1 gross (0.6 net) wells drilled and waiting on completion and/or pipeline connection. Our 2011 production in the Niobrara was 154 MBOE (423 Bbls/d), compared to 2010 production, which was insignificant given we completed our first well in late 2010. Total proved reserves for the Niobrara were 1 MMBOE at December 31, 2011, approximately 88%, or 884 MBOE, of which was crude oil and liquids. We are seeking a joint venture partner for our Niobrara properties in an effort to accelerate value realization from such assets, although there can be no assurance that we will be able to enter into a joint venture for such assets on terms that are acceptable to us or at all.

Utica Shale

In 2011, we commenced acquiring acreage in the Utica Shale located in eastern Ohio and northwestern Pennsylvania. Our activities in the Utica Shale are currently conducted through a joint venture described below.

Avista Utica Joint Venture

Effective September 2011, our wholly-owned subsidiary, Carrizo (Utica) LLC, entered into a joint venture with ACP II Marcellus LLC, which is also our joint venture partner in the Marcellus Shale (ACP II) and ACP III Utica LLC (ACP III), affiliates of Avista Capital Holdings, LP, a private equity firm (collectively with ACP II and ACP III, Avista). Under the terms of this joint venture, we and Avista have the right to contribute cash and properties to acquire and develop acreage in the Utica Shale play.

The properties initially dedicated to this joint venture consist of approximately 15,000 net acres in eastern Ohio and northwestern Pennsylvania, as well as any future properties acquired by either party within Ohio, and at the contributing party s option, elsewhere in the Utica Shale play. Under the terms of the joint venture agreement, our participating interest in the joint venture properties is initially 10% and Avista s initial participating interest is 90%. Avista has the right to contribute aggregate funds of up to $130.0 million to the joint venture initially, with the ability to raise this amount by an incremental $70.0 million. As of December 31, 2011, our Utica joint venture with Avista held approximately 20,406 net acres in Ohio and Pennsylvania.

We have been granted a 12-month option (expiring in September 2012) to increase our participating interest in the 15,000 net acres initially dedicated to the joint venture and certain other related acreage acquisitions to 50%, and an 18-month option (expiring in March 2013) to increase our participating interest in other properties that may be acquired by the joint venture to 50%. Our purchase options may be exercised at specified increments above acreage cost and associated improvements at any time during the applicable option period. The exercise deadlines for both options are accelerated in connection with a sale by Avista of substantially all of its interests in the Utica joint venture properties.

We will initially serve as operator of the Utica joint venture properties and will provide certain management services to Avista related to the Utica joint venture. Avista or its designee has the right to become a co-operator of the joint venture properties if we exercise our 18-month option and (i) Avista sells substantially all of its interests in the Utica joint venture properties or (ii) we default under the terms of any pledge of our interest in the Utica joint venture properties. Avista has the ability to cause us to resign as

operator and appoint Avista or Avista s designee as operator of the properties if we do not exercise our 18-month option by such option s deadline (or, in such case, Avista may request that we continue as contract operator), or if we default under the terms of any pledge of our interest in the Utica joint venture properties at any time when we have not exercised our 18-month option.

In addition to our share in the production and sale proceeds from the Utica joint venture properties, we also acquired in the transaction interests in ACP III (B Units) that entitle us to increasing percentages of ACP III s distributions of proceeds from properties subsequently acquired by this joint venture to ACP III s members if specified internal rates-of-return and return-on-investment thresholds with respect to Avista s investments in ACP III are achieved. Our B Units interest in ACP III provide consent rights only in limited circumstances and generally do not entitle us to vote or participate in the management of ACP III, which is controlled by its members who are Avista affiliates. Our B Units in ACP III will terminate upon (i) the exercise and closing of our 18-month option to increase our interest in the properties subsequently acquired by the joint venture or (ii) the sale of substantially all of our interest in the joint venture properties other than in connection with a sale by Avista of substantially all of its interest in the Utica joint venture. In addition, our existing B Units interest in ACP II pursuant to the Avista Marcellus joint venture (described below under Natural Gas Plays Avista Marcellus Joint Venture) was amended to entitle us to a portion of ACP II s distributions of proceeds from the properties initially dedicated to the Avista Utica joint venture to its members, provided that specified internal rates-of-return and return-on-investment thresholds are achieved, unless and until we increase our interest in such properties through our 12-month option or sell substantially all of our interest in such properties. Termination of the ACP III management services agreement under certain circumstances will also result in the termination of our rights to distributions under the B Units described in this paragraph.

The area of mutual interest for the Utica joint venture, consisting of the portions of the State of Ohio that are prospective for Utica Shale exploration, will remain in place until the earliest to occur of the following events, at which time the area of mutual interest will only continue to apply to those areas where the joint venture is active: (i) September 1, 2014, (ii) ACP III s investment reaches $100.0 million, (iii) upon ACP II s or ACP III s request to be designated (or have its designee designated) as a co-operator of the properties following exercise of our 18-month option, (iv) upon our required designation of ACP II or ACP III (or either s designee) as a co-operator of the applicable properties in connection with a default by us under the terms of any pledge of our interest in the Utica joint venture properties, (v) the sale by Avista of substantially all of its interest in the Utica joint venture properties or (vi) termination of the ACP III management services agreement.

Each party s ability to transfer its interest in the Utica joint venture to third parties is generally subject to tag along rights. Avista s tag along rights do not apply upon a change of control of Carrizo. Our interests are subject to drag along rights in connection with sales by Avista of all of its Utica joint venture interests unless we exercise our 18-month option, with respect to properties subsequently acquired by the Utica joint venture, and our 12-month option, with respect to properties initially dedicated to the Utica joint venture and certain related properties. Prior to the exercise of our 18-month option, we generally may not transfer less than substantially all of our interest in the Utica joint venture properties without Avista s consent.

Steven A. Webster, Chairman of our Board of Directors, serves as Co-Managing Partner and President of Avista Capital Holdings, LP, which entity has the ability to control Avista and its affiliates. ACP II s and ACP III s Boards of Managers have the sole authority for determining whether, when and to what extent any cash distributions will be declared and paid to members of ACP II or ACP III, respectively. Mr. Webster is not a member of either entity s Board of Managers. As previously disclosed, we have been a party to prior arrangements with affiliates of Avista Capital Holdings LP, including in respect of our existing joint venture with Avista in the Marcellus Shale. The terms of the joint ventures with Avista in the Utica Shale and the Marcellus Shale were approved by a special committee of Carrizo s disinterested directors. See also Natural Gas Plays Avista Marcellus Joint Venture and Note 10 to our Consolidated Financial Statements.

U.K. North Sea

We use a low cost entry business model in the U.K. North Sea that allows us to acquire prospective acreage without making any initial capital commitments. This strategy led directly to the acquisition of our interest in the Huntington Field discovery located primarily on block 22/14b, where we retain a 15% working interest. The Huntington Forties reservoir development plan was approved by our joint venture and the U.K. Department of Energy and Climate Change in November 2010 and the field is under development with initial production currently expected in the fourth quarter of 2012. The field is being developed with horizontal producer wells and two vertical water injection wells. As of February 27, 2012, three of the four producer wells and one of the injector wells had been successfully drilled and completed. The other injection well and the other producer well are expected to be completed by mid-August, well in advance of first production. We currently anticipate that our share of production, once the initial production plateau is reached after field startup, will be approximately 4,500 BOE per day. As of December 31, 2011, our proved reserves in the Huntington Forties reservoir were approximately 6 MMBOE, approximately 87% of which was crude oil.

In January 2011, we and our Carrizo UK Huntington Ltd. (Carrizo UK) subsidiary, as borrower, entered into a senior secured multicurrency credit facility agreement secured by substantially all of Carrizo UK s assets with limited recourse to us (the Huntington Facility). The Huntington Facility provides financing for a substantial portion of Carrizo UK s 15% share of the development costs associated with the Huntington Field development project through a term loan facility, a cost overrun facility and a letter of credit facility. We currently believe that amounts available under the Huntington Facility will be sufficient to meet Carrizo UK s share of capital expenditures through field start-up. We also continue to consider the sale of all or a portion of our interest in the Huntington Field, although there can be no assurance that we will be able to complete a transaction on terms that are acceptable to us or at all.

In addition to the license containing our Huntington Field development, as of February 27, 2012, we held interests in four other licenses. By virtue of our bid exploration strategy, each of these licenses is within ten miles of established facilities, allowing the use of existing infrastructure. We currently have satisfied or believe that we can satisfy all remaining committed work obligations on these four licenses at no material additional cost to the Company.

Natural Gas Plays

At December 31, 2011, our natural gas proved reserves were 728 Bcf, a 9% increase from 670 Bcf at December 31, 2010, approximately 90% of which was located in the Barnett Shale. Our natural gas production increased to 38.9 Bcf (107 MMcf/d) in 2011, a 14% increase from the 34.1 Bcf (93 MMcf/d) in 2010.

Barnett Shale

In 2003, we began active participation in the Barnett Shale through acquisition of acreage. As of December 31, 2011, we held interests in approximately 34,313 gross (24,666 net) acres, 270 gross (171.1 net) producing wells and 23 gross (6.1 net) wells that were drilled but waiting on completion and/or pipeline connection. Of these wells, we operated 186 gross (156.1 net) producing wells and 7 gross (2.5 net) wells drilled and waiting on completion and/or pipeline connection. During 2011, we drilled 48 gross wells (15.3 net), of which we operated 17 gross wells (9.1 net), and completed and brought on production 60 gross wells (28.0 net). Approximately 82% of our 34,313 gross acres in the Barnett Shale is either in currently designated producing units or in units on which wells have been drilled and are waiting on completion and/or pipeline connection. Our 2011 production in the Barnett Shale was a record 36 Bcfe, 12% above 2010 production of 32 Bcfe. Total proved reserves for the Barnett Shale were 658 Bcfe at December 31, 2011, approximately 99%, or 654 Bcfe, of which was natural gas.

As of December 31, 2011, we were not operating any drilling rigs in the Barnett Shale and expect (i) to participate in drilling only one or two wells in the Barnett Shale through 2012 and (ii) to complete hydraulic fracturing of the 8.7 net wells remaining in our wells inventory of drilled but not yet completed. We currently expect our 2012 Barnett Shale drilling efforts to require an investment of approximately $15 million for drilling and completion costs.

In May 2011, the Company sold a substantial portion of its non-core area Barnett Shale properties to KKR Natural Resources (KKR), a partnership formed between an affiliate of Kohlberg Kravis Roberts & Co, L.P., and Premier Natural Resources. Net proceeds received from the sale were approximately $98.0 million, which represents an agreed upon purchase price of approximately $104.0 million less net purchase price adjustments.

Marcellus Shale

We began active participation in the Marcellus Shale in 2007. The Marcellus Shale is substantially larger in aerial extent (over 63 million acres) than the Barnett Shale (over 3 million acres in the core areas of the Barnett) and the Marcellus Shale, in general, is found in considerably less densely populated areas than the Barnett Shale. We believe that we can leverage the knowledge and experience that we gained in the Barnett Shale to effectively explore for and develop natural gas in the Marcellus Shale. Our activities in the Marcellus Shale are currently conducted through two joint ventures described below.

As of December 31, 2011, we owned interests in 291,167 gross (109,782 net) acres in the Marcellus Shale, principally in Pennsylvania, West Virginia and New York. During 2011, we drilled 34 gross wells (10.5 net), of which we operated 31 gross wells (10.4 net), and completed and brought on production 5 gross wells (1.9 net). We commenced producing from our first operated Marcellus well in late October 2011 when the Laser pipeline was completed and brought on line. As of December 31, 2011, we had a backlog of 28 gross (8.6 net) wells in Northeastern Pennsylvania that were drilled and waiting on completion or pipeline connection, or both. Total proved reserves for the Marcellus Shale were 37 Bcfe at December 31, 2011, all of which was natural gas.

In 2012, we plan to spend approximately $62.0 million in the Marcellus Shale, all of which we expect to use for drilling, completion, seismic and other infrastructure development in Pennsylvania. These amounts do not include an estimated $18.6 million of our share of costs that will be carried by our Pennsylvania joint venture partner, Reliance Marcellus II, LLC. As a result of the material decline in natural gas prices, we and our joint venture partners are carefully reviewing our drilling program and have significantly reduced our planned spending in the Marcellus shale during 2012. We will continue to monitor prices and, consistent with our existing contractual commitments, may decrease our activity level and capital expenditures further, or may increase such activity, if natural gas prices so warrant. In New York, we are currently evaluating a portion of our prospective Marcellus Shale acreage for Trenton-Black River prospects. We currently have four rigs that we operate or under agreement to begin operating in the Marcellus Shale in the early part of 2012.

Avista Marcellus Joint Venture

Effective as of August 2008, our wholly-owned subsidiary, Carrizo (Marcellus) LLC, entered into a joint venture with ACP II, an affiliate of Avista with which we also have a joint venture in the Utica Shale. See also Crude Oil and Liquids Plays Avista Utica Joint Venture and Note 10 to our Consolidated Financial Statements.

We serve as operator of the properties covered by this joint venture and also perform specified management services for ACP II. An operating committee composed of one representative of each party provides overall supervision and direction of joint operations. Avista or its designee has the right to become a co-operator of the Marcellus joint venture properties if all of its membership interests or substantially all of its assets are sold to an unaffiliated third party or if we default under the terms of any pledge of our interest in the Marcellus joint venture properties.

Subject to specified exceptions (including the Reliance transactions described below), net cash flow from hydrocarbon production from the Marcellus joint venture properties and related sales proceeds, if such properties are sold, will be allocated (a) 75% to Avista and 25% to us until Avista has recovered the remainder of its investment, (b) thereafter, 100% to us until we recover an equal amount and (c) thereafter in accordance with the parties participating interests, which are currently 50/50. We have also agreed to jointly market Avista s share of the production from the Marcellus joint venture properties with our own until the cash flows and sale proceeds are allocated in accordance with the parties participating interests under this joint operating agreement. In addition to our share in the production and sale proceeds from the Marcellus joint venture properties, we were issued B Units in ACP II, that entitles us to increasing percentages of ACP II s distributions to Avista if specified internal rates-of-return and return on-investment thresholds with respect to Avista s investment in ACP II are achieved. Our interest in ACP II provides consent rights only in limited, specified circumstances and generally does not entitle us to vote or participate in the management of ACP II, which is controlled by its members and affiliates. During 2011 and 2010, we received cash distributions of $3.3 million and $38.8 million, respectively, on our B Unit investment in ACP II as a result of ACP II s distribution to Avista of proceeds from its sale of oil and gas properties to an affiliate of Reliance described below. We do not expect to receive any additional distributions on our B Unit investment in ACP II s as a result of distributions to Avista in connection with its sale to an affiliate of Reliance, but we retain the right to receive distributions on account of future distributions from ACP II to Avista from its sale of oil and gas properties in New York and West Virginia in certain circumstances, although we retain the right to receive distributions on our B Unit investment in ACP II as a result of distributions to Avista associated with properties initially dedicated to the Avista Utica joint venture described above in Crude Oil and Liquids Plays and Projects Avista Utica Joint Venture.

Each party s ability to transfer its interest in the Marcellus joint venture properties to third parties is subject in most instances to preferential purchase rights for transfers of less than 10% of its interest in such joint venture properties, or to tag along rights for most other transfers.

As part of the closing of the transactions with Reliance described below, we and Avista amended our then-existing joint venture agreements to provide that the properties that we and Avista sold to Reliance, as well as the properties we committed to the joint venture with Reliance, are not subject to the terms of our Marcellus joint venture with Avista, and that the area of mutual interest of our Marcellus joint venture with Avista will generally not include Pennsylvania, in which those properties are located. Our Marcellus joint venture with Avista will otherwise continue and, as of December 31, 2011, included approximately 142,653 net acres, primarily in West Virginia and New York. Pursuant to the terms of the Avista area of mutual interest, effective December 31, 2010, the initial area of mutual interest was reduced to specified halos in which the Marcellus joint venture with Avista was active.

Reliance Joint Venture

In September 2010, we completed the sale of 20% of our interests in substantially all of our oil and gas properties in Pennsylvania that had been subject to the Avista Marcellus joint venture to Reliance Marcellus II, LLC, (Reliance) a wholly-owned subsidiary of Reliance Holding USA, Inc. and an affiliate of Reliance Industries Limited, for $13.1 million in cash and a commitment by Reliance to pay 75% of certain of our future development costs up to approximately $52.0 million, as further described below. Simultaneously with the closing of this transaction, ACP II closed the sale of its entire interest in the same properties to Reliance for a purchase price of approximately $327.0 million. In December 2010, we entered into a settlement agreement with Reliance providing for the resolution of defects in title that Reliance alleged with respect to the properties it acquired from us and Avista. In the agreement, we agreed to undertake specified curative measures with respect to the properties we and Avista sold to Reliance, and to indemnify Reliance on our own behalf and on behalf of Avista with respect to any specified third party claims (in addition to existing customary indemnification obligations under the purchase agreement). In connection with entering into the settlement agreement, we entered into an agreement with Avista by which it agreed to indemnify us for amounts we pay on its behalf under the settlement agreement, if any.

In connection with these sale transactions, we and Reliance also entered into agreements to form a new joint venture with respect to the interests purchased by Reliance from us and Avista. The Carrizo/Reliance joint venture agreement included approximately 108,105 net acres in northern and central Pennsylvania as of December 31, 2011. Under the terms of the agreement, we generally retained a 40% working interest in the acreage and Reliance generally owns a 60% working interest. In addition to funding its own share of future development obligations, Reliance agreed to fund 75% of our portion of these costs until September 2013 or until the earlier full utilization of the up to $52.0 million development carry, subject to certain conditions and extensions. As of December 31, 2011, there was $30.7 million in development carry yet to be utilized.

We have agreed to various restrictions on our ability to transfer our properties covered by the Reliance joint venture. Additionally, following the expiration of the Reliance development carry, we are subject to a mutual right of first offer on direct and indirect property transfers for the remainder of a ten-year development period (through September 2020), subject to specified exceptions. We have also granted an option in favor of Reliance to purchase a 60% (as adjusted over time) share of acreage purchased directly or indirectly by us after the closing. This option, which covers substantially all of Pennsylvania, is exercisable at our cost plus, in the case of direct property sales, a specified premium, and is subject to specified exceptions. We serve as operator of the properties covered by this joint venture, with Reliance having the right to assume operatorship of 60% of undeveloped acreage in portions of central Pennsylvania beginning as early as September 2011 and, for a period through September 2014 to purchase all of our 40% interest in such acreage at a specified price. Operations under the joint venture will generally be required to conform to a budget approved by an operating committee that includes representatives of both parties, subject to exceptions, including those for sole risk operations and in the event of defaults by the parties. The parties have also generally agreed until 2013 to forego the ability conduct sole risk operations and to certain other limits to such operations thereafter. Reliance has also agreed to certain limitations with respect to specified actions taken with respect to us.

Other Project Areas in the United States

In addition to our core plays and project areas, we have additional wells, acreage positions and limited reserves in the onshore Gulf Coast area, the Camp Hill Field in Texas and certain other resource plays. Our total proved reserves in these other areas are 26 Bcfe, or less than 3% of our total proved reserves.

Business Strategy

Measured Growth Through the Drillbit

Our objective is to increase value through the execution of a business strategy focused on organic growth through the drillbit. Key elements of our business strategy include:

Grow Primarily Through Drilling. We pursue a technology-driven exploration drilling program. We generate exploration prospects through geological and geophysical analysis of 3-D seismic and other data. Our ability to successfully define and drill exploratory prospects is demonstrated by our 100% drilling success rate in the Barnett Shale area since our entrance into the play in 2003. We expect to allocate approximately 95% of our 2012 capital expenditure plan for drilling and development.

Pursue Growth in Crude Oil and Liquids-Rich Plays. Since April 2010, we have pursued a growth strategy in crude oil and liquids-rich plays driven by the attractive economics associated with those commodities. We moved quickly to implement this strategy and at December 31, 2011 we owned 41,044 net acres in the Eagle Ford Shale, 58,255 net acres in the Niobrara, and in the Utica Shale owned a 10% interest in 20,406 acres with the option to acquire an additional 40% interest in those 20,406 acres. In 2011, we drilled 30 gross (23 net) horizontal wells in the Eagle Ford Shale and 8 gross (4.7 net) horizontal wells in the Niobrara.

Control Operating and Capital Costs. We emphasize efficiencies to lower our costs to find, develop and produce our oil and gas reserves. This includes concentrating on our core areas, which allows us to optimize drilling and completion techniques, as well as benefit from economies of scale. In addition, as we operate a significant percentage of our properties, the majority of our capital expenditure plan is discretionary allowing us the ability to reduce or reallocate our spending in response to changes in market conditions. For example, our discretionary capital spending has been strategically redeployed to pursue growth in crude oil and liquids-rich plays.

Maintain Our Financial Flexibility. We are committed to preserving our financial flexibility. We have historically funded our capital program with a combination of cash generated from operations, proceeds from the sale of non-core assets, proceeds from sales of securities, proceeds, payments or carried interest from our joint ventures with GAIL, Reliance and Avista and borrowings under our credit facilities. We currently expect to continue these activities in 2012.

Focus on Areas Where We Have Experience and a Technical Advantage. We believe we have developed a technical advantage from our extensive experience drilling over 260 horizontal wells in the Barnett Shale, where our management, technical staff and field operations teams have significant experience. We are now leveraging this advantage in other shale trends, principally in the Eagle Ford Shale, the Niobrara, and the Marcellus and Utica Shales. We plan to focus a majority of our capital expenditures in these core areas, where we have acquired, or are acquiring significant acreage positions and a large prospect inventory.

Maintain a Conservative Exploration and Development Portfolio. We continue to focus our primary exploration effort and capital program on resource plays, where individual wells tend to have lower risk and moderate potential, such as our development drilling in the Eagle Ford and Marcellus Shales.

Manage Risk Exposure. We seek to limit our financial and operating risks by varying our level of participation in drilling prospects with differing risk profiles and by seeking well-funded partners to ensure that we are able to move forward on projects in a timely manner. Our joint ventures with Reliance in most of Pennsylvania, with Avista in the Utica Shale and other parts of the Marcellus Shale, with GAIL in the Eagle Ford Shale and with an affiliate of Sumitomo Corporation in the Barnett Shale are prominent examples of this strategy. We also attempt to limit our exposure to reductions in natural gas prices by actively hedging production. As of December 31, 2011, we had hedged approximately 18,943,000 MMBtus and 1,024,800 Bbls of forecasted natural gas and oil production, respectively through 2012. Our current long-term strategy is to manage exposure for a substantial, but varying, portion of forecasted production up to 36 months.

Our Competitive Strengths

We believe we have the following competitive strengths that will support our efforts to successfully execute our business strategy:

Large inventory of drilling prospects. We have developed a significant inventory of future drilling locations, primarily in our well-established position in LaSalle county in the Eagle Ford Shale and Weld and Morgan counties in the Niobrara. As of December 31, 2011, we owned leases covering approximately 205,679 gross acres in our focus areas of the Eagle Ford Shale and Niobrara. At December 31, 2011, we also had a substantial inventory of already drilled wells that were waiting on hydraulic fracturing, completion or pipeline connection, including 12 gross wells (9.2 net) in the Eagle Ford Shale and 1 gross well (0.6 net) in the Niobrara Shale. Approximately 51% of our estimated proved reserves at December 31, 2011 were undeveloped and an additional 8% were developed, non-producing reserves. In addition, as part of our growth strategy in crude oil and liquid-rich plays, we had acquired or had the right to acquire over 10,203 net leasehold acres in the Utica Shale at December 31, 2011.

Successful drilling history. We follow a disciplined approach to drilling wells by applying proven horizontal drilling and hydraulic-fracturing technology. Since our entrance into the Barnett Shale in 2003, our drilling success rate in the Barnett Shale has been 100%. Additionally, we rely on advanced technologies such as 3-D seismic and microseismic analysis, to better define geologic risk and enhance the results of our drilling efforts.

Experienced management and professional workforce. We employ 46 oil and gas professionals, including geophysicists, petrophysicists, geologists, petroleum engineers and production and reservoir engineers and technical support staff, who have an average of over 19 years of experience. We believe our experience and expertise, particularly as they relate to successfully identifying and developing resource plays, is a competitive advantage.

Operational control. As of December 31, 2011, we operated approximately 66.3% of the wells in which we held an interest. Of those wells we operate, we hold an average interest of approximately 82.8%. Our significant operational control provides us with the flexibility to align capital expenditures with cash flow as we are generally able to adjust drilling plans in response to changes in commodity prices.

EXPLORATION APPROACH

Our exploration strategy in our shale resource plays has been to accumulate significant leasehold positions in areas with known shale thickness and thermal maturity in the proximity of known or emerging pipeline infrastructures. A component of our exploitation strategy is to first identify and acquire surface tracts or well pads from which multiple wells can be drilled. We then seek to acquire contiguous lease blocks in the areas immediately adjacent to these well pads that can be developed quickly. We next acquire 3-D seismic data over these leases to assist in well placement and development optimization. Even in the relatively lower-risk, reserve-proven trends, such as the Niobrara, Marcellus Shale and Barnett Shale, 3-D seismic data interpretation is instrumental in our development program, significantly reducing geologic risk and allowing optimal well paths and spacing. Finally, we form drilling units and utilize sophisticated horizontal drilling, multi-stage simultaneous hydraulic fracturing programs and micro-seismic techniques designed to maximize the production rate and recoverable reserves from a unit area. Primarily due to the continuing down-turn in natural gas prices, we seek to reduce costs by drilling more wells on units where we hold a lower working interest than our historic average. In addition, we seek to enter into joint ventures with well-funded partners that will pay a disproportionate share of the drilling and completion costs of wells that we drill. In 2011, we sold 20% of our interests in certain of our Eagle Ford Shale properties to GAIL who agreed to pay 50% of certain of our drilling and completion costs up to approximately $31.3 million, which we currently expect to fully utilize by the end of the first quarter of 2012. In 2010, we sold 20% of our interests in our Pennsylvania properties to Reliance who agreed to pay 75% of certain of our drilling and completion costs up to approximately $52.0 million, of which we also currently expect to utilize a substantial portion this year. In 2009, we entered into a strategic alliance with a subsidiary of Sumitomo Corporation of Japan, wherein we sold to it a 12.5% working interest in 16 of our drilling units in the Barnett Shale. Sumitomo agreed to pay approximately 16.7% of the drilling and completion costs on many of the future wells in these units to earn the 12.5% working interest. In certain instances we also seek to maximize the acreage that we can hold by drilling and producing by temporarily drilling fewer wells on each drilling unit in order to permit us to develop more drilling units with comparatively fewer rigs. Where possible, we also seek to maximize our liquidity, while increasing profitability of our projects through timing the hydraulic fracturing, completion and pipeline connection costs of our horizontal wells to coincide with periods of lower services costs.

We strive to achieve a balance between acquiring acreage, seismic data (2-D and 3-D) and timely project evaluation through the drillbit to ensure that we minimize the costs to test for commercial reserves while building a significant acreage position. Our first exploration wells in these trends are frequently vertical wells, or a limited number of horizontal wells, because they allow us to evaluate thermal maturity and rock property data, while also permitting us to test various hydraulic fracturing and completion techniques without incurring the cost of drilling a substantial number of horizontal wells. As discussed above, we have also shifted our focus toward crude oil and liquids-rich plays to take advantage of the attractive economics associated with those commodities.

We maintain a flexible and diversified approach to project identification by focusing on the estimated financial results of a project area rather than limiting our focus to any one method or source for obtaining leads for new project areas. Additionally, we monitor competitor activity and review outside prospect generation by small, independent prospect generators. We complement our exploratory drilling portfolio through the use of these outside sources of project generation and typically retain operator rights. Specific drill-sites are typically chosen by our own geoscientists or, in highly populated or environmentally sensitive areas, are dictated by available leases.

OPERATING APPROACH

Our management team has extensive experience in the development and management of exploration and development projects in the Barnett Shale and along the Gulf Coast. We believe that the experience we have gained in the Barnett Shale, along with our extensive experience in hydraulic fracturing and horizontal drilling technologies and the experience of our management in the development, processing and analysis of 3-D projects and data in the Barnett Shale, onshore Gulf Coast and, more recently, the Marcellus Shale, Eagle Ford Shale and Niobrara, will play a significant part in our future success.

We generally seek to obtain lease operator status and control over field operations, and in particular seek to control decisions regarding 3-D survey design parameters and drilling and completion methods. As of December 31, 2011, we operated 349 gross (288.8 net) producing oil and gas wells. We generally seek to control operations for most new exploration and development taking advantage of our technical staff experience in horizontal drilling and hydraulic fracturing. During 2011, we operated all 30 of the gross wells drilled in the Eagle Ford Shale, 7 of the 8 gross wells drilled in the Niobrara, 19 of the 48 gross wells drilled in the Barnett Shale, and 31 of the 34 gross wells drilled in the Marcellus Shale.

ADDITIONAL OIL AND GAS DISCLOSURES

Working Interest and Drilling in Project Areas

The actual working interest we will ultimately own in a well will vary based upon several factors, including the depth, cost and risk of each well relative to our strategic goals, activity levels and capital availability. From time to time some fraction of these wells may be sold to industry partners either on a prospect by prospect basis or a program basis. In addition, we may also contribute acreage to larger drilling units thereby reducing prospect working interest. We have, in the past, retained less than 100% working interest in our drilling prospects. References to our interests are not intended to imply that we have or will maintain any particular level of working interest.

Although we have identified or allocated our capital expenditure plan to numerous drilling prospects, we may not be able to lease or drill those prospects within our expected time frame or at all. Wells may currently be part of our capital expenditure plan based on statistical results of drilling activities in other project areas that we believe are geologically similar rather than on analysis of seismic or other data in the prospect area, in which case actual drilling and results are likely to vary, possibly materially, from those statistical results. In addition, our drilling schedule may vary from our expectations because of future uncertainties. Our final determination of whether to drill wells included in our capital expenditure plan will be dependent on a number of factors, including (1) the results of our exploration efforts and the acquisition, review and analysis of the seismic data; (2) the availability of sufficient capital resources to us and the other participants for the drilling of the prospects; (3) the approval of the prospects by the other participants after additional data has been compiled; (4) economic and industry conditions at the time of drilling, including prevailing and anticipated prices for oil and gas and the availability and prices of drilling rigs and hydraulic fracturing crews; and (5) the availability of leases and permits on reasonable terms for the prospects. There can be no assurance that these projects can be successfully developed or that any identified drill sites or wells included in our capital expenditure plan will, if drilled, encounter reservoirs of commercially productive oil or gas. We may seek to sell or reduce all or a portion of our interest in a project area or with respect to prospects or wells within a project area.

Our success will be materially dependent upon the success of our exploratory drilling program, which is an activity that involves numerous risks. See Item 1A. Risk Factors Oil and gas drilling is a speculative activity and involves numerous risks and substantial and uncertain costs that could adversely affect us.

Oil and Gas Reserves

The following table sets forth our estimated net proved oil and gas reserves and the PV-10 value of such reserves as of December 31, 2011. The reserve data and the present value as of December 31, 2011 were prepared by LaRoche Petroleum Consultants, Ltd., Ryder Scott Company Petroleum Engineers and Fairchild and Wells, Inc. For further information concerning these independent third party engineers estimates of our proved reserves at December 31, 2011, see the reserve reports included as exhibits to this Annual Report on Form 10-K. The PV-10 value was prepared using an unweighted arithmetic average of the first day of the month oil and gas prices for each month in the prior twelve-month period ended December 31, 2011, discounted at 10% per annum on a pre-tax basis, and is not intended to represent the current market value of the estimated oil and gas reserves owned by us. For further information concerning the present value of future net revenues from these proved reserves, see Note 2. Summary of Significant Accounting Policies and Note 14. Supplemental Disclosures About Oil and Gas Producing Activities (Unaudited) in the Notes to our Consolidated Financial Statements.

Summary of Oil and Gas Reserves as of December 31, 2011

Based on Average 2011 Prices

(Dollars in thousands)

	Oil, Condensate and Natural Gas Liquids (MBbls)	Natural Gas (MMcf)	Total (Mmcfe) (1)	PV-10 Value (2) (3)
U.S. Proved				
Developed	7,989	389,795	437,729	$ 731,032
Undeveloped	21,233	333,052	460,448	343,476
Total Proved	29,222	722,847	898,177	1,074,508
U.K. Proved				
Developed	2,719	2,419	18,730	196,086
Undeveloped	2,718	2,419	18,729	178,442
Total Proved	5,437	4,838	37,459	374,528
Total Proved				
Developed	10,708	392,214	456,459	927,118
Undeveloped	23,951	335,471	479,177	521,918
Total Proved	34,659	727,685	935,636	$ 1,449,036

(1) Natural gas equivalents are determined using the ratio of 6 Mcf of natural gas to 1 Bbl of crude oil or natural gas liquids which represents their approximate relative energy content. Despite holding this ratio constant at six Mcf to one Bbl, current prices are substantially higher for oil than natural gas on an energy equivalent basis, although there have been periods in which they have been lower or substantially lower.

(2) The PV-10 value as of December 31, 2011 is pre-tax and was determined by using the average of oil and gas prices at the beginning of each month in the twelve-month period prior to December 31, 2011, which averaged $92.76 per Bbl of oil, $44.90 per Bbl of natural gas liquids and $3.21 per Mcf of natural gas in the United States and $106.90 per Bbl of oil and $7.54 per Mcf of natural gas for the North Sea. Management believes that the presentation of PV-10 value may be considered a non-GAAP financial measure as defined in Item 10(e) of Regulation S-K. Therefore, we have included a reconciliation of the measure to the most directly comparable GAAP financial measure (standardized measure of discounted future net cash flows in footnote (3) below). Management believes that the presentation of PV-10 value provides useful information to investors because it is widely used by analysts and investors in evaluating oil and gas companies. Because many factors that are unique to each individual company may impact the amount of future income taxes to be paid, the use of the pre-tax measure provides greater comparability when evaluating companies. It is relevant and useful to investors for evaluating the relative monetary significance of our oil and gas properties. Further, investors may utilize the measure as a basis for comparison of the relative size and value of our reserves to other oil and gas companies. Management also uses this pre-tax measure when assessing the potential return on investment related to its oil and gas properties and in evaluating acquisitions. The PV-10 value is not a measure of financial or operating performance under GAAP, nor is it intended to represent the current market value of the estimated oil and gas reserves owned by us. PV-10 value should not be considered in isolation or as a substitute for the standardized measure of discounted future net cash flows as defined under GAAP.

(3) Future income taxes and present value discounted (10%) future income taxes were $724.1 and $408.0 million, respectively. Accordingly, the after-tax PV-10 value of Total Proved Reserves (or standardized measure of discounted future net cash flows) is $1,041.0 million.

Proved Undeveloped Reserves

United States. At December 31, 2011 and 2010, we had 460.4 Bcfe and 401.6 Bcfe of proved undeveloped reserves, respectively. In 2011, we (a) added 209.6 Bcfe, which included 102.0 Bcfe, 80.8 Bcfe, and 26.3 Bcfe of proved undeveloped reserves as a result of drilling and additional offset locations in the Eagle Ford, Barnett, and Marcellus Shales, respectively, (b) converted a net of 39.8 Bcfe of reserves from proved undeveloped to proved developed, primarily in the Eagle Ford Shale and Barnett Shale, (c) sold 74.6 Bcfe of proved undeveloped reserves in the Barnett Shale and (d) removed 20.0 Bcfe of proved undeveloped reserves in the Barnett Shale due to a shift in future drilling priorities focusing more on crude oil and liquids-rich plays.

Costs incurred relating to the development of proved undeveloped reserves were approximately $57.0 million in 2011, as compared to $35.9 million in 2010. Costs incurred relating to the development of proved undeveloped reserves are currently projected to be approximately $461.6 million in 2012, $423.4 million in 2013, and $191.1 million in 2014. All proved undeveloped reserves drilling locations are scheduled to be drilled prior to the end of 2016.

U.K. North Sea. At December 31, 2011 and 2010, we had 18.7 Bcfe and 36.3 Bcfe of proved undeveloped reserves, respectively. In 2011, we converted 18.7 Bcfe of reserves from proved undeveloped to proved developed and added 1 Bcfe due to revisions for price.

Costs incurred relating to the development of proved undeveloped reserves were approximately $38.8 million in 2011, as compared to $5.4 in 2010. Costs incurred relating to the development of proved undeveloped reserves are currently projected to be approximately $25.4 million in 2012. All proved undeveloped reserves drilling locations are scheduled to be drilled prior to the end of 2012.

Other

Reserve Matters. No estimates of proved reserves comparable to those included herein have been included in reports to any federal agency other than the Securities and Exchange Commission (SEC). The reserves data set forth in this Annual Report on Form 10-K represents only estimates. See Item 1A. Risk Factors Our reserve data and estimated discounted future net cash flows are estimates based on assumptions that may be inaccurate and are based on existing economic and operating conditions that may change in the future. All of our proved reserves are determined by independent third party engineers.

Our future oil and gas production is highly dependent upon our level of success in finding or acquiring additional reserves. See Item 1A. Risk Factors We depend on successful exploration, development and acquisitions to maintain reserves and revenue in the future. Also, the failure of an operator of our wells to adequately perform operations, or such operator s breach of the applicable agreements, could adversely impact us. See Item 1A. Risk Factors We cannot control the activities on properties we do not operate and are unable to ensure their proper operation and profitability.

In accordance with SEC regulations, LaRoche Petroleum Consultants, Ltd., Ryder Scott Company Petroleum Engineers and Fairchild and Wells, Inc. each used the price based on the unweighted average of oil and gas prices at the beginning of each month in the twelve-month period ended December 31, 2011, adjusted for basis and quality differentials. The prices used in calculating the estimated future net revenue attributable to proved reserves do not necessarily reflect market prices for oil and gas production subsequent to December 31, 2011. There can be no assurance that all of the proved reserves will be produced and sold within the periods indicated, that the assumed prices will actually be realized for such production or that existing contracts will be honored or judicially enforced.

LaRoche Petroleum Consultants, Ltd. determined 658 Bcfe, or 70% of our proved reserves (all of which were located in the Barnett Shale), for the year ended December 31, 2011. Ryder Scott Company Petroleum Engineers determined 261 Bcfe, or 28% of our proved reserves (everywhere other than the Barnett Shale and the Camp Hill Field), for the year ended December 31, 2011. Fairchild and Wells, Inc. determined 17 Bcfe, or 2% of our proved reserves (all of which were located in the Camp Hill Field), for the year ended December 31, 2011.

Qualifications of Third Party Engineers

As discussed above, we engaged LaRoche Petroleum Consultants, Ltd., Ryder Scott Company Petroleum Engineers and Fairchild and Wells, Inc., independent third party reserve engineers, to perform independent estimates of our proved reserves. The technical person responsible for review of our reserve estimates at each of these firms meets the requirements regarding qualifications, independence, objectivity and confidentiality set forth in the Standards Pertaining to Estimating and Auditing of Oil and Gas Reserves Information promulgated by the Society of Petroleum Engineers. None of these firms own an interest in our properties or is employed on a contingent fee basis.

Internal Controls

A significant component of our internal controls in our reserve estimation effort is our practice of using independent third-party reserve engineering firms to determine 100% of our year-end reserves. The qualifications of each of these firms are discussed above under Qualifications of Third Party Engineers.

Our internal reserve engineers are three individuals at the Company who are primarily responsible for reviewing the reserves estimates prepared by our third party engineering firms. Each of these individuals has over 25 years of experience in the petroleum industry and extensive experience in the estimation of reserves and the review of reserve reports prepared by third party engineering firms.

These three individuals along with other Company personnel, review the inputs and assumptions made in the reserve estimates prepared by the third party engineer firms and assess them for reasonableness. The reserve reports are also reviewed by senior management, including the Chief Executive Officer, who is a registered petroleum engineer and holds a B. S. in Mechanical Engineering from the University of Colorado and the Chief Operating Officer, who holds a B.S. in Petroleum Engineering from Texas A&M University.

Oil and Gas Reserve Replacement

Finding and developing sufficient amounts of oil and gas reserves at economical costs are critical to our long-term success. Given the inherent decline of hydrocarbon reserves resulting from production, it is important for an exploration and production company to demonstrate a long-term trend of more than offsetting produced volumes with new reserves that will provide for future production. Management uses the reserve replacement ratio, as defined below, as an indicator of our ability to replenish annual production volumes and grow our reserves, thereby providing some information on the sources of future production. We believe reserve replacement information is frequently used by analysts, investors and others in the industry to evaluate the performance of companies like ours. The reserve replacement ratio is calculated by dividing the sum of reserve additions from all sources (revisions, extensions, discoveries, other additions, acquisitions and sales of reserves in place) by the actual production for the corresponding period. The values for these reserve additions are derived directly from the proved reserves table above. We do not use unproved reserve quantities in calculating our reserve replacement ratio. It should be noted that the reserve replacement ratio is a statistical indicator that has limitations. As an annual measure, the ratio is limited because it typically varies widely based on the extent and timing of new discoveries and property acquisitions. Its predictive and comparative value is also limited for the same reasons. In addition, since the ratio does not take into consideration the cost or timing of future production of new reserves, it cannot be used as a measure of value creation. The ratio does not distinguish between changes in reserve quantities that are producing and those that will require additional time and funding to begin producing. It is relevant to note the percentage of our reserves that were producing in the United States was 41% in 2011, 45% in 2010 and 45% in 2009. The reduction in the percentage of proved producing reserves in 2011, compared to 2010 and 2009, was largely attributable to the inclusion of proved non-producing reserves in the North Sea as a consequence of the Huntington Field development drilling and facility construction that occurred in 2011. We currently expect all of these reserves to be producing by year-end 2012. Set forth below is our reserve replacement ratio for the years ended December 31, 2011, 2010 and 2009. We have no reserves that are producing in the U.K. North Sea.

	2011	2010	2009
United States			
Reserve replacement	308%	650%	400%
Reserve replacement excluding divestitures	628%	650%	400%
World-wide Reserve Replacement Ratio			
Reserve replacement	311%	749%	400%
Reserve replacement excluding divestitures	631%	749%	400%

Oil and Gas Volumes, Prices and Production Expense

The following table sets forth certain information regarding the production volumes of, average sales prices received for and average production costs associated with our sales of oil and gas for the periods indicated.

	Year Ended December 31,		
	2011	2010	2009
Production volumes			
Oil (MBbls)	802	176	174
Natural gas (MMcf)	38,991	34,092	30,027
NGLs (MMcf)	1,257	1,659	1,975
Natural gas equivalent (MMcfe)	45,060	36,807	33,046
Average sales prices			
Oil (per Bbl)	$ 94.16	$ 78.64	$ 58.85
Natural gas (per Mcf)	2.98	3.33	3.11
NGLs (per Mcf)	8.40	6.43	4.65
Natural gas equivalent (per Mcfe)	4.49	3.75	3.41
Average costs (per Mcfe)(1)	$ 0.46	$ 0.52	$ 0.91

(1) Includes direct lifting costs (labor, repairs and maintenance, materials and supplies), workover costs, transportation costs and the administrative costs of production offices, and insurance and property.

Acquisition, Exploration and Development Capital Expenditures and Finding and Development Costs

Our finding and development costs for the years ended December 31, 2011, 2010 and 2009 are reflected in the table below.

	Year Ended December 31,		
	2011	2010	2009
	(In thousands, except Mmcfe/MBOE and per Mcfe/BOE amounts)		
Unproved property acquisition costs	$ 109,216	$ 127,589	$ 35,248
Exploration costs	374,366	139,862	77,255
Development costs	58,544	62,952	55,270
Asset retirement obligations	6,018	1,031	(1,390)
Total costs incurred (1)	$ 548,144	$ 331,434	$ 166,383
Mcfe			
Average all-sources finding cost (per Mcfe)	$ 3.92	$ 1.20	$ 1.26
Average finding and development cost (per Mcfe)(2)	3.80	0.95	1.16
Average drilling finding cost (per Mcfe)	3.14	0.74	0.99
Average all-sources finding cost excluding divestitures (per Mcfe)	1.93	1.20	1.26
BOE			
Average all-sources finding cost (per BOE)	$ 23.52	$ 7.21	$ 7.54
Average finding and development cost (per BOE)(2)	22.80	5.70	6.96
Average drilling finding cost (per BOE)	18.84	4.44	5.94
Average all-sources finding cost excluding divestitures (per BOE)	11.58	7.21	7.54

(1) Total costs incurred include capitalized overhead of $9.6 million, $5.3 million and $5.6 million and exclude capitalized interest on unproved properties of $23.4 million, $20.7 million and $19.7 million for the years ended December 31, 2011, 2010 and 2009, respectively.

(2) Comprised of all exploration and development costs incurred in the year plus the leasehold and seismic costs attributable to all proved drilling locations additions in the year.

For the three-year period ended December 31, 2011, our total cost for exploration, development and acquisition activities was approximately $1,046 million. Total exploration, development and acquisition activities for the three-year period ended December 31, 2011 have added approximately 547.8 Bcfe of net proved reserves at an all-sources finding cost of $1.91 per Mcfe.

Our finding and development cost computation excludes net additions/(reductions) to total future development costs with respect to proved developed non-producing and proved undeveloped properties necessary to convert those properties into proved producing properties of $531.3 million, $379.0 million and $(12.3) million at December 31, 2011, 2010 and 2009, respectively, and includes net additions to proved developed non-producing and proved undeveloped reserves of 86.5 Bcfe, 132.5 Bcfe and 38.6 Bcfe for the years ended December 31, 2011, 2010 and 2009, respectively. Accordingly, had we included future development costs in our computations, the average all-sources finding costs would have been $7.65 ($3.80 excluding divestitures), $2.44 and $1.16 per Mcfe for the years ended December 31, 2011, 2010 and 2009, respectively. Year on year, future development costs increased in 2011 by approximately $531.3 million net, largely comprised of (1) a $555.6 million increase in the Eagle Ford Shale for the development costs attributable to an 9.9 MMBOE ($56/BOE) increase in proved developed non-producing and proved undeveloped reserves, (2) a $1.6 million increase in the Niobrara for the development costs attributable to an 0.1 MMBOE ($16/BOE) increase in proved developed non-producing and proved undeveloped reserves, (3) a $30.2 million increase in the Marcellus future development costs attributable to a 25.3 Bcfe ($1.19/Mcfe) increase in proved developed non-producing and proved undeveloped reserves, and (4) a $22.0 million net decrease in the Barnett Shale future development costs comprised of (a) an approximate $70.4 million increase in future development costs associated with the net additions of 94.7 Bcfe ($0.74/Mcfe) to proved developed non-producing and proved undeveloped reserves, (b) a net $92.4 million reduction associated with a decrease of 92.3 Bcfe ($1.00/Mcfe) to proved developed non-producing and proved undeveloped wells, primarily from wells sold during the year or that are currently not in the drilling plan as we shift our drilling efforts to crude oil and liquids-rich plays.

In order to maintain continued growth, our annual goal is to add new reserves exceeding our yearly production at a finding and development cost that contributes to an acceptable profit margin. Accordingly, we use the finding and development cost in combination with our reserve replacement ratio, as previously defined, to measure our operating and financial performance.

Our all-source finding cost measure is a measure with limitations. Consistent with industry practice, our finding and development costs have historically fluctuated on a year-to-year basis based on a number of factors including the extent and timing of new discoveries and property acquisitions. Due to the timing of proved reserve additions and timing of the related costs incurred to find and develop our reserves, our all-sources finding cost measure often includes quantities of reserves for which a majority of the costs of development have not yet been incurred. Conversely, the measure often includes costs to develop proved reserves that had been added in earlier years. Finding and development costs, as measured annually, may not be indicative of our ability to economically replace oil and gas reserves because the recognition of costs may not necessarily coincide with the addition of proved reserves. Our all-sources finding cost may also be calculated differently than the comparable measure of other oil and gas companies.

Drilling Activity

The following table sets forth our drilling activity for the years ended December 31, 2011, 2010 and 2009 by geographical area. In the table, gross refers to the total wells in which we have a working interest and net refers to gross wells multiplied by our working interest therein.

	Year Ended December 31,					
	2011		2010		2009	
	Gross	Net	Gross	Net	Gross	Net
Exploratory Wells - Productive						
United States	88	38.4	57	28.9	46	22.4
U.K. North Sea						
Total	88	38.4	57	28.9	46	22.4
Exploratory Wells - Nonproductive						
United States	1	0.5	3	2.3	1	0.8
U.K. North Sea						
Total	1	0.5	3	2.3	1	0.8
Development Wells - Productive						
United States	33	15.0	28	13.4	16	13.0
U.K. North Sea	2	0.3				
Total	35	15.3	28	13.4	16	13.0
Development Wells - Nonproductive						
United States						
U.K. North Sea						

Total

The wells are in various stages of development and/or stages of production.

As of December 31, 2011, we are in the process of drilling 12 gross (6.8 net) wells in the United States. We are also in the process of drilling 1 gross (0.2 net) well in the U.K. These wells are not included in the table above.

Productive Wells

The following table sets forth the number of productive oil and gas wells in which we owned an interest as of December 31, 2011.

	Company Operated		Non-Operated		Total	
	Gross	Net	Gross	Net	Gross	Net
Oil	126	116.4	8	2.7	134	119.1
Natural gas	223	172.4	169	25.5	392	197.9
Total	349	288.8	177	28.2	526	317.0

Acreage Data

The following table sets forth certain information regarding our developed and undeveloped lease acreage as of December 31, 2011. Developed acreage refers to acreage on which wells have been drilled or completed to a point that would permit production of oil and gas in commercial quantities. Undeveloped acreage refers to acreage on which wells have not been drilled or completed to a point that would permit production of oil and gas in commercial quantities whether or not the acreage contains proved reserves.

	Developed Acreage		Undeveloped Acreage		Total	
	Gross	Net	Gross	Net	Gross	Net
Eagle Ford Shale - Texas (1)	15,516	12,075	82,611	28,969	98,127	41,044
Niobrara Formation - Colorado	6,084	5,375	101,468	52,880	107,552	58,255
Barnett Shale - Texas	28,197	20,055	6,116	4,611	34,313	24,666
Marcellus Shale						
New York	2,117	158	31,417	6,752	33,534	6,910
Pennsylvania	3,393	1,210	130,792	45,688	134,185	46,898
West Virginia	801	389	116,662	52,629	117,463	53,018
Virginia and other	53	26	5,932	2,930	5,985	2,956
Marcellus Shale Total	6,364	1,783	284,803	107,999	291,167	109,782
Other (2)	34,323	16,357	167,604	111,718	201,927	128,075
Total United States	90,484	55,645	642,602	306,177	733,086	361,822
Total U.K. North Sea	1,767	265	121,179	85,804	122,946	86,069
Total	92,251	55,910	763,781	391,981	856,032	447,891

(1) Included in the table above is approximately 7,000 net acres that are subject to drill-to-earn agreements. We expect adequate capital, equipment and personnel will allow us to drill the necessary wells within the required periods.

(2) Other includes other non-resource plays in Texas and Louisiana; the Camp Hill Field; Utica Shale in Ohio and Pennsylvania; Fayetteville Shale in Arkansas; the New Albany Shale in Kentucky and Illinois; the Floyd/Neal Shale in Mississippi; the Barnett/Woodford in West Texas and New Mexico; and the Bakken in North Dakota.

Our lease agreements generally terminate if producing wells have not been drilled on the acreage within their primary term or an extension thereof (a period that can be from three to 10 years depending on the area). If no production is established on our leases that are in their primary term, approximately 15% of our acreage will expire in 2012, 34% will expire in 2013 and 8% will expire in 2014. Substantially all of any acreage allowed to expire in 2012 is expected to relate to non-core acreage where we have limited remaining amounts of unproved property costs.

Marketing

Our production is marketed to third parties consistent with industry practices. Typically, our oil and gas is sold at the wellhead to unaffiliated third parties. Oil is sold at field-posted prices plus a bonus and natural gas is sold under contract at a negotiated price which is based on quoted prices for specified locations, such as WAHA or Houston Ship Channel, and then discounted back to the wellhead based upon a number of factors normally considered in the industry, such as distance from the well to the central sales point, well pressure, quality of natural gas and prevailing supply and demand conditions. We have made the strategic decision to sell as much of our natural gas production at the wellhead as possible, so that we can concentrate our efforts and resources on exploration and production which we believe are more consistent with our competitive expertise, rather than in natural gas pipeline operation, natural gas marketing and sales. As a consequence, we sell the majority of our natural gas at the wellhead to Enterprise Products Operating LLC in the Barnett Shale and to DTE Energy in the Marcellus Shale. In each case we sell at competitive market prices based on a differential to several sales points. We do not believe the loss of any one of our purchasers would materially affect our ability to sell the oil and gas we produce. We believe other purchasers are available in all our areas of operations.

Our marketing objective is to receive the highest possible wellhead price for our product. We are aided by the presence of multiple outlets near our production in the Eagle Ford Shale, Barnett Shale area and the Texas and Louisiana onshore Gulf Coast area.

There are a variety of factors that affect the market for oil and gas generally, including:

- demand for oil and gas;
- the extent of production of oil and gas and, in particular, domestic production and imports;
- the proximity and capacity of natural gas pipelines and other transportation facilities;
- the marketing of competitive fuels; and
- the effects of state and federal regulations on oil and gas production and sales.

See Item 1A. Risk Factors Oil and gas prices are highly volatile, and lower oil and gas prices will negatively affect our financial results, We are subject to various governmental regulations and environmental risks, and The marketability of our natural gas production depends on facilities that we typically do not own or control, which could result in a curtailment of production and revenues.

In addition to selling our oil and gas at the wellhead, we work with various pipeline companies to procure and to assure capacity for our natural gas. In late 2009, we entered into a strategic alliance with Delphi Midstream Partners LLC to provide gathering and midstream pipeline solutions for our Marcellus Shale production in portions of Northern Pennsylvania. We also conduct an active hedging program in order to ensure stable cash flow to fund our exploration and production activities. All of these hedging transactions provide for financial rather than physical settlement. For a discussion of these matters, our hedging policy and recent hedging positions, see Item 7. Management s Discussion and Analysis of Financial Condition and Results of Operations Summary of Critical Accounting Policies Derivative Instruments, Item 7A. Qualitative and Quantitative Disclosures About Market Risk Commodity Risk, and Item 1A. Risk Factors We may continue to enter into derivative financial instruments to manage the price risks associated with our production. Our derivative financial instruments may result in our making cash payments or prevent us from benefiting from increases in prices for oil and gas and If our access to markets is restricted, it could negatively impact our production, our income and ultimately our ability to retain our leases. Our ability to sell natural gas and/or receive market prices for our natural gas may be adversely affected by pipeline and gathering system capacity constraints.

Competition and Technological Changes

We encounter competition from other oil and gas companies in all areas of our operations, including the acquisition of exploratory prospects and proven properties. Many of our competitors are large, well-established companies that have been engaged in the oil and gas business for much longer than we have and possess substantially larger operating staffs and greater capital resources than we do. We may not be able to conduct our operations, evaluate and select suitable properties and consummate transactions successfully in this highly competitive environment.

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The oil and gas industry is characterized by rapid and significant technological advancements and introductions of new products and services using new technologies. If one or more of the technologies we use now or in the future were to become obsolete or if we are unable to use the most advanced commercially available technology, our business, financial condition and results of operations could be materially adversely affected.

Regulation

Oil and gas operations are subject to various federal, state, local and international environmental regulations that may change from time to time, including regulations governing oil and gas production and transportation, federal and state regulations governing environmental quality and pollution control and state limits on allowable rates of production by well or proration unit. These regulations may affect the amount of oil and gas available for sale, the availability of adequate pipeline and other regulated 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 oil and gas, protect rights to produce oil and gas between owners in a common reservoir, control the amount of oil and gas produced by assigning allowable rates of production, provide nondiscriminatory access to common carrier pipelines and control contamination of the environment. Pipelines are subject to the jurisdiction of various federal, state and local agencies. We are also subject to changing and extensive tax laws, the effects of which cannot be predicted.

The following discussion summarizes the regulation of the United States oil and gas industry. We believe we are in substantial compliance with the various statutes, rules, regulations and governmental orders to which our operations may be subject, although we cannot assure you that this is or will remain the case. Moreover, those statutes, rules, regulations and government orders may be changed or reinterpreted from time to time in response to economic or political conditions, and any such changes or reinterpretations could materially adversely affect our results of operations and financial condition. The following discussion is not intended to constitute a complete discussion of the various statutes, rules, regulations and governmental orders to which our operations may be subject.

Regulation of Natural Gas and Oil Exploration and Production

Our operations are subject to various types of regulation at the federal, state and local levels that:

- require permits for the drilling of wells;
- mandate that we maintain bonding requirements in order to drill or operate wells; and
- regulate 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 regulations govern the size of drilling and spacing units or proration units, the density of wells that may be drilled in oil and gas properties and the unitization or pooling of oil and gas properties. In this regard, some states (including Louisiana) allow the forced pooling or integration of tracts to facilitate exploration while other states (including Texas) rely primarily or exclusively on voluntary pooling of lands and leases. In areas where pooling is primarily or exclusively 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 establish maximum rates of production from oil and gas wells generally prohibit the venting or flaring of natural gas and impose specified requirements regarding the ratability of production. The effect of these regulations may limit the amount of oil and gas 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. Because these laws and regulations are frequently expanded, amended and reinterpreted, 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 we produce and the manner in which our production is transported and marketed. Under the Natural Gas Act of 1938 (NGA), the Federal Energy Regulatory Commission (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 of our sales of our own production. As a result, all of our domestically produced natural gas is sold at market prices, subject to the terms of any private contracts that may be in effect. The FERC s jurisdiction over interstate natural gas transportation, however, was not affected by the Decontrol Act.

Under the NGA, facilities used in the production or gathering of natural gas are exempt from the FERC s jurisdiction. We own certain natural gas pipelines that we believe satisfy the FERC s criteria for establishing that these are all gathering facilities not subject to FERC jurisdiction under the NGA. State regulation of gathering facilities generally includes various safety, environmental, and in some circumstances, nondiscriminatory take requirements but does not generally entail rate regulation. Some of the delay in bringing our natural gas to market has been the lack of available pipeline systems in the Barnett Shale, particularly those that would take natural gas production from the lease to existing infrastructure. In order to partly alleviate this issue, commencing in 2009, certain of our wholly-owned subsidiaries have constructed non-jurisdictional gathering facilities in cases where we have determined that we can construct those facilities more quickly or more efficiently than waiting on an unrelated third-party pipeline company.

One of our pipeline subsidiaries, Hondo Pipeline Inc., exercises the power of eminent domain and transports gas for third parties and is a regulated public utility within the meaning of Section 101.003 (GURA) and Section 121.001 (the Cox Act) of the Texas Utilities Code. Both GURA and the Cox Act prohibit unreasonable discrimination in the transportation of natural gas and authorize the Texas Railroad Commission to regulate gas transportation rates. However, GURA provides for negotiated rates with transportation, industrial or similar large-volume contract customers so long as neither party has an unfair negotiating advantage, the negotiated rate is substantially the same as that negotiated with at least two other customers under similar conditions, or sufficient competition existed when the rate was negotiated.

Although we do not own or operate any pipelines or facilities that are directly regulated by the FERC, its regulations of third-party pipelines and facilities could indirectly affect our ability to market our production. Beginning in the 1980s the FERC initiated a series of major restructuring orders that required pipelines, among other things, to perform open access transportation, unbundle their sales and transportation functions, and allow shippers to release their pipeline capacity to other shippers. As a result of these changes, sellers and buyers of natural 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.

In the past, Congress has been very active in the area of natural gas regulation. However, the more recent trend has been in favor of deregulation or lighter handed regulation and the promotion of competition in the gas industry. In light of this increased reliance on competition, the Energy Policy Act of 2005 amended the NGA to prohibit any forms of market manipulation in connection with the transportation, purchase or sale of natural gas. In addition to the regulations implementing these prohibitions, the FERC has established new regulations that are intended to increase natural gas pricing transparency through, among other things, expanded dissemination of information about the availability and prices of gas sold and new regulations that require both interstate pipelines and certain non-interstate pipelines to post daily information regarding their design capacity and daily scheduled flow volumes at certain points on their systems. The Energy Policy Act of 2005 also significantly increased the penalties for violations of the NGA and the FERC s regulations to up to $1.0 million per day for each violation.

Oil Price Controls and Transportation Rates

Our sales of crude oil, condensate and natural gas liquids are not currently regulated and are made at market prices. The price we receive from the sale of these products may be affected by the cost of transporting the products to market. Much of that 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 specified conditions and limitations. These regulations may tend to increase the cost of transporting crude oil and natural gas liquids by interstate pipeline, 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 December 2010, to implement the third 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 2.65 percent (PPI plus 2.65 percent) should be the oil pricing index for the five-year period beginning July 1, 2011. We are not able at this time to predict the effects of this indexing system or any new FERC regulations on the transportation costs associated with oil production from our oil producing operations.

There regularly are legislative proposals pending in the federal and state legislatures which, 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, we cannot predict whether or to what extent the trend toward federal deregulation of the petroleum industry will continue, or what the ultimate effect on our sales of oil, gas and other petroleum products will be.

Environmental Regulations

Our operations are subject to numerous international, federal, state and local laws and regulations governing the discharge of materials into the environment or otherwise relating to environmental protection. These laws and regulations may require the acquisition of a permit before drilling commences, restrict the types, quantities and concentration of various substances that can be released into the environment in connection with drilling and production activities, limit or prohibit drilling activities on specified lands within wilderness, wetlands and other protected areas, require remedial measures to mitigate pollution from former operations, such as pit closure and plugging abandoned wells, and impose substantial liabilities for pollution resulting from production and drilling operations. The failure to comply with these laws and regulations may result in the assessment of administrative, civil and criminal penalties, imposition of investigatory or remedial obligations or the issuance of injunctions prohibiting or limiting the extent of our operations. Public interest in the protection of the environment has increased dramatically in recent years. The trend of applying more expansive and stricter environmental legislation and regulations to the oil and gas industry could continue, resulting in increased costs of doing business and consequently affecting our profitability. To the extent laws are enacted or other governmental action is taken that restricts drilling or imposes more stringent and costly waste handling, disposal and cleanup requirements, our business and prospects could be adversely affected.

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

We currently own or lease numerous properties that for many years have been used for the exploration and production of oil and gas. Although we believe that we have implemented appropriate operating and waste disposal practices, prior owners and operators of these properties may not have used similar practices, and hydrocarbons or other waste may have been disposed of or released on or under the properties we own or lease or on or under locations where such waste have been taken for disposal. In addition, many of these properties have been operated by third parties whose treatment and disposal or release of hydrocarbons or other waste was not under our control. These properties and the waste disposed thereon may be subject to the Comprehensive Environmental Response, Compensation and Liability Act (CERCLA), RCRA and analogous state laws as well as state laws governing the management of oil and gas waste. Under these laws, we could be required to remove or remediate previously disposed waste (including waste 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. See Item 1A. Risk Factors We are subject to various environmental risks and governmental regulations, including those relating to benzene emissions and hydraulic fracturing, and new regulations may be more stringent.

CERCLA, also known as the Superfund law, and analogous state laws impose liability, without regard to fault or the legality of the original conduct, on specified classes of persons that are considered to have contributed to the release of a hazardous substance into the environment. These classes of 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.

Our operations may be subject to the Clean Air Act and comparable state and local requirements. In 1990 Congress adopted amendments to the Clean Air Act containing provisions that have resulted in the gradual imposition of certain pollution control requirements with respect to air emissions from our operations. The EPA and states have developed and continue to develop regulations to implement these requirements. We may be required to incur certain capital expenditures in the next several years for air pollution control equipment in connection with maintaining or obtaining operating permits and approvals addressing other air emission-related issues. Moreover, changes in environmental laws and regulations occur frequently, and stricter laws, regulations or enforcement policies could significantly increase our compliance costs. Further, stricter requirements could negatively impact our production and operations. For example, the Texas Commission on Environmental Quality has finalized revisions to certain air permit programs that significantly increase the air permitting requirements for new and certain existing oil and gas production and gathering sites for 23 counties in the Barnett Shale production area. These initiatives could lead to more stringent air permitting, increased regulation and possible enforcement actions at the local, state, and federal levels. Additionally, the EPA has issued proposed rules that would subject all oil and gas operations (production, processing, transmission, storage and distribution) to regulation under the New Source Performance Standards and National Emission Standards for Hazardous Air Pollutants programs. For more information, please read Part II, Item 1A. Risk Factors We are subject to various environmental risks and governmental regulations, including those relating to benzene emissions and hydraulic fracturing, and new regulations may be more stringent.

Federal regulations require certain owners or operators of facilities that store or otherwise handle oil, such as us, to prepare and implement spill prevention, control, countermeasure and response plans relating to the possible discharge of oil into surface waters. The Oil Pollution Act of 1990 (OPA) contains numerous requirements relating to the prevention of and response to oil spills into waters of the United States. The OPA subjects owners of facilities to strict joint and several liability for all containment and cleanup costs and certain other damages arising from a spill, including, but not limited to, the costs of responding to a release of oil to surface waters. The OPA also requires owners and operators of offshore facilities that could be the source of an oil spill into federal or state waters, including wetlands, to post a bond, letter of credit or other form of financial assurance in amounts ranging from $10.0 million in specified state waters to $35.0 million in federal outer continental shelf waters to cover costs that could be incurred by governmental authorities in responding to an oil spill. These financial assurances may be increased by as much as $150.0 million if a formal risk assessment indicates that the increase is warranted. Noncompliance with OPA may result in varying civil and criminal penalties and liabilities. Our operations are also subject to the federal Clean Water Act (CWA) and analogous state laws. In accordance with the CWA, the State of Louisiana issued regulations prohibiting discharges of produced water in state coastal waters effective July 1, 1997. Pursuant to other requirements of the CWA, the EPA has adopted regulations concerning discharges of storm water runoff. This program requires covered facilities to obtain individual permits or seek coverage under an EPA general permit. Like OPA, the CWA and analogous state laws relating to the control of water pollution provide varying civil and criminal penalties and liabilities for releases of petroleum or its derivatives into surface waters or into the ground. Similarly, the U.S. Congress has considered legislation to subject hydraulic fracturing operations to federal regulation and to require the disclosure of chemicals used by us and others in the oil and gas industry in the hydraulic fracturing process. Please read Item 1A. Risk Factors We are subject to various environmental risks and governmental regulations, including those relating to benzene emissions and hydraulic fracturing, and new regulations may be more stringent.

We also are subject to a variety of federal, state, local and foreign permitting and registration requirements relating to protection of the environment. We believe we are in substantial compliance with current applicable environmental laws and regulations and that continued compliance with existing requirements will not have a material adverse effect on our financial position or results of operations.

Our offshore operations in the U.K. North Sea and onshore operations in the U.S. are subject to similar regulations covering permit requirements and the discharge of oil and other contaminants in connection with drilling operations.

Global Climate Change

There is increasing attention in the United States and worldwide being paid to the issue of climate change and the contributing effect of greenhouse gas (GHG) emissions. On December 15, 2009, the EPA published a Final Rule, also known as the EPA s Endangerment Finding, finding that current and projected concentrations of six key GHGs in the atmosphere threaten the environment and public health and the welfare of current and future generations. Based on these findings, the EPA adopted two sets of regulations that restrict emissions of GHGs under existing provisions of the federal Clean Air Act, including one that requires a reduction in emissions of GHGs from motor vehicles and another that regulates GHG emissions from certain large stationary sources under the Clean Air Act Prevention of Significant Deterioration (PSD) and Title V permitting programs. The stationary source rule tailors the PSD and Title V programs to apply to certain stationary sources of GHG emissions, to be phased in through a multistep process, with the largest sources being the first subject to permitting. Facilities required to obtain PSD permits for their GHG emissions also will be required to meet best available control technology standards, which will be established by the states or, in some instances, by the EPA on a case-by-case basis. The EPA also expanded its existing GHG emissions reporting rule to apply to the oil and gas source category, including oil and natural gas production facilities and natural gas processing, transmission, distribution and storage facilities, beginning in 2012 for emissions occurring in 2011. In addition, the U.S. Congress has considered a number of legislative proposals to restrict GHG emissions and more than 20 states, either individually or as part of regional initiatives, have begun taking actions to control and/or reduce GHG emissions. Moreover, in 2005, the Kyoto Protocol to the 1992 United Nations Framework Convention on Climate Change, which establishes a binding set of emission targets for GHGs, became binding on all those countries that had ratified it. International discussions are ongoing to develop an international scheme for the regulation and reduction of GHGs, such as the

United Nations Climate Change Conference in Durban, South Africa in 2011. While it is not possible at this time to predict how regulation that may be enacted to address GHG emissions would impact our business, the modification of existing laws or regulations or the adoption of new laws or regulations curtailing oil and gas exploration in the areas of the United States or the North Sea in which we operate could materially and adversely affect our operations by limiting drilling opportunities or imposing materially increased costs. In addition, existing or new laws, regulations or treaties (including incentives to conserve energy or use alternative energy sources) could have a negative impact on our business if such incentives reduce demand for oil and gas.

In addition to the effects of future regulation, the meteorological effects of global climate change could pose additional risks to our onshore and offshore operations in the form of more frequent and/or more intense storms and flooding, which could in turn adversely affect our cost of doing business.

Operating Hazards and Insurance

The oil and gas business involves a variety of operating hazards and risks that could result in substantial losses to us from, among other things, injury or loss of life, severe damage to or destruction of property, natural resources and equipment, pollution or other environmental damage, cleanup responsibilities, regulatory investigation and penalties and suspension of operations.

In addition, we may be liable for environmental damages caused by previous owners of property we purchase and lease. As a result, we may incur substantial liabilities to third parties or governmental entities, the payment of which could reduce or eliminate the funds available for exploration, development or acquisitions or result in the loss of our properties.

In accordance with customary industry practices, we maintain insurance against some, but not all, potential losses. We do not carry business interruption insurance or protect against loss of revenues. We cannot assure you that any insurance we obtain will be adequate to cover any losses or liabilities. We cannot predict the continued availability of insurance or the availability of insurance at premium levels that justify its purchase. We may elect to self-insure if we believe that the cost of available insurance is excessive relative to our assessment of the risks presented. In addition, pollution and environmental risks generally are not fully insurable. The occurrence of an event not fully covered by insurance could have a material adverse effect on our financial condition and results of operations.

We participate in a number of our wells on a non-operated basis, and may be accordingly limited in our ability to control the risks associated with oil and gas operations.

Title to Properties; Acquisition Risks

We believe we currently have satisfactory title to all of our producing properties in the specific areas in which we operate except where failure to do so would not have a material adverse effect on our business and operations in each such area. Our properties are subject to customary royalty interests, liens incident to operating agreements, liens for current taxes and other burdens which we believe do not materially interfere with the use of or affect the value of these properties. As is customary in the industry in the case of undeveloped properties, we perform limited investigations of record title at the time of acquisition (other than a preliminary review of local records). Investigations, including a title opinion of local counsel, are generally made in conjunction with the commencement of drilling operations. Even then, particularly in urban settings, the cost of performing detailed title work can be expensive. We may choose to forego detailed title examination by title lawyers on a portion of the mineral leases that we place in a drilling unit or conduct less title work than we have traditionally performed. Our U.S. senior secured revolving credit facility, or our revolving credit facility, is secured by substantially all of our proved producing domestic oil and gas properties.

In acquiring producing properties, we assess the recoverable reserves, future domestic oil and gas prices, operating costs, potential liabilities and other factors relating to the properties. Our assessments are necessarily inexact and their accuracy is inherently uncertain. Our review of a subject property in connection with our acquisition assessment will not reveal all existing or potential problems or permit us to become sufficiently familiar with the property to fully assess its deficiencies and capabilities. We may not inspect every well, and we may not be able to observe structural and environmental problems even when we do inspect a well. If problems are identified, the seller may be unwilling or unable to provide effective contractual protection against all or part of those problems. Any acquisition of property interests may not be economically successful, and unsuccessful acquisitions may have a material adverse effect on our financial condition and results of operations. See Item 1A. Risk Factors Our future acquisitions may yield revenues or production that varies significantly from our projections.

Customers

We sold oil and gas production to the following customer representing at least 10% of our oil and gas revenues as follows:

	Year Ended December 31,		
	2011	2010	2009
DTE Energy Trading, Inc.	43%	63%	54%

We do not believe the loss of any one of our purchasers would materially affect our ability to sell the oil and gas we produce. We believe other purchasers are available in our areas of operations. See Additional Oil and Gas Disclosures Marketing.

Employees

At December 31, 2011, we had 169 full-time employees. We believe that our relationships with our employees are good.

In order to optimize prospect generation and development, we utilize the services of independent consultants and contractors to perform various professional services, particularly in the areas of 3-D seismic data mapping, acquisition of leases and lease options, construction, design, well site surveillance, permitting and environmental assessment. Independent contractors generally provide field and on-site production operation services, such as pumping, maintenance, dispatching, inspection and testing. We believe that this use of third-party service providers has enhanced our ability to contain general and administrative expenses.

Available Information

Our website address is www.crzo.net. We make our website content available for informational purposes only. It should not be relied upon for investment purposes, nor is it incorporated by reference in this Form 10-K. We make available on our website, through a direct link to the SEC s website at www.sec.gov, free of charge, our annual report on Form 10-K, quarterly reports on Form 10-Q, current reports on Form 8-K and amendments to those reports as soon as reasonably practicable after we electronically file such materials with, or furnish them to, the SEC. You may read and copy any materials we file with the SEC at the SEC s Public Reference Room at 1100 F Street, N.E., Washington, D.C. 20549. You may obtain information regarding the Public Reference Room by calling the SEC at 1-800-SEC-0330.

You may also find information related to our corporate governance, board committees and company code of ethics at our website. Among the information you can find there is the following:

- Audit Committee Charter;
- Compensation Committee Charter;
- Nominating and Corporate Governance Committee Charter;
- Code of Ethics and Business Conduct; and
- Compliance Employee Report Line.

We intend to satisfy the requirement under Item 5.05 of Form 8-K to disclose any amendments to our Code of Ethics and Business Conduct and any waiver from a provision of our Code of Ethics by posting such information on our website at www.crzo.net under About Carrizo Oil & Gas, Inc. Governance.

Glossary of Certain Industry Terms

The definitions set forth below shall apply to the indicated terms as used herein. All volumes of natural gas referred to herein are stated at the legal pressure base of the state or area where the reserves exist and at 60 degrees Fahrenheit and in most instances are rounded to the nearest multiple or power of ten.

After payout. With respect to an oil or gas interest in a property, refers to the time period after which the costs to drill and equip a well have been recovered.

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

Bbls/d. Stock tank barrels per day.

Bcf. Billion cubic feet.

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

Before payout. With respect to an oil or gas interest in a property, refers to the time period before which the costs to drill and equip a well have been recovered.

BOE. A BOE is determined using the ratio of six Mcf of natural gas to one Bbl of oil, condensate or natural gas liquids, which approximates the relative energy content of oil, condensate and natural gas liquids as compared to natural gas. Despite holding this ratio constant at six Mcf to one Bbl, prices have historically often been higher or substantially higher for oil than natural gas on an energy equivalent basis, although there have been periods in which they have been lower or substantially lower.

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 oil or natural gas, or in the case of a dry well, the reporting to the appropriate authority that the well has been abandoned.

Condensate. Condensate is a mixture of hydrocarbons that exists in the gaseous phase at original reservoir temperature and pressure, but that, when produced, is in the liquid phase at surface pressure and temperature.

Developed acreage. The number of acres assignable to productive wells.

Developed oil and gas reserves. Developed oil and gas reserves are reserves of any category that can be expected to be recovered (i) through existing wells with existing equipment and operating methods or in which the cost of the required equipment is relatively minor compared to the cost of a new well; and (ii) through installed extraction equipment and infrastructure operational at the time of the reserves estimate if the extraction is by means not involving a well. This definition has been abbreviated from the applicable definition contained in Rule 4-10(a)(6) of Regulation S-X.

Development Costs. Costs incurred to obtain access to proved reserves and to provide facilities for extracting, treating, gathering and storing the oil and gas. Development costs, including depreciation and applicable operating costs of support equipment and facilities and other costs of development activities, are incurred to (i) gain access to and prepare well locations for drilling, including surveying well locations for the purpose of determining specific development drilling sites, clearing ground, draining, road building and relocating public roads, gas lines and power lines, to the extent necessary in developing the proved reserves, (ii) drill and equip development wells, development-type stratigraphic test wells and service wells, including the costs of platforms and of well equipment such as casing, tubing, pumping equipment, and the wellhead assembly, (iii) acquire, construct and install, production facilities such as leases, flow lines, separators, treaters, heaters, manifolds, measuring devices and production storage tanks, natural gas cycling and processing plants, and central utility and waste disposal systems, and (iv) provide improved recovery systems.

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

Dry well. An exploratory, development or extension well that proves to be incapable of producing either oil or natural gas in sufficient quantities to justify completion as an oil or natural gas well.

Economically producible. The term economically producible, as it relates to a resource, means a resource which generates revenue that exceeds, or is reasonably expected to exceed, the costs of the operation. The value of the products that generate revenue shall be determined at the terminal point of oil and gas producing activities as defined in Rule 4-10(a)(16) of Regulation S-X.

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 oil or natural gas in another reservoir.

Farm-in or farm-out. An agreement where under the owner of a working interest in an oil and gas lease assigns the working interest or a portion thereof to another party who desires to drill on the leased acreage. Generally, the assignee is required to drill one or more wells in order to earn its interest in the acreage. The assignor usually retains a royalty or reversionary interest in the lease. The interest received by an assignee is a farm-in while the interest transferred by the assignor is a farm-out.

Field. An area consisting of a single reservoir or multiple reservoirs all grouped on or related to the same individual geological structural feature and/or stratigraphic condition. The geological terms structural feature and stratigraphic condition are intended to identify localized geological features as opposed to the broader terms of basins, trends, provinces, plays, areas of interest, etc.

Finding costs. Costs associated with acquiring and developing proved oil and gas reserves which are capitalized by us pursuant to U.S. generally accepted accounting principles, or GAAP, including all costs involved in acquiring acreage, geological and geophysical work and the cost of drilling and completing wells.

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

Hydraulic fracturing. Hydraulic fracturing is the process of stimulation using a liquid (usually water with an amount of chemicals mixed in) that is forced into an underground formation under high pressure and a proppant (usually sand or ceramics) to prop open the fracture after they are opened by the liquid, on reservoirs with low permeability to stimulate and improve the flow of hydrocarbons from these reservoirs. Hydraulic fracturing is an essential technology in shale reservoirs and other unconventional resource plays where nearly all wells are fractured in order to enable commercial hydrocarbon production.

MBbls. One thousand barrels of oil or other liquid hydrocarbons.

MBbls/d. One thousand barrels of oil or other liquid hydrocarbons per day.

Mcf. One thousand cubic feet of natural gas.

Mcf/d. One thousand cubic feet of natural gas per day.

Mcfe. One thousand cubic feet equivalent, determined using the ratio of six Mcf of natural gas to one Bbl of oil, condensate or natural gas liquids. Despite holding this ratio constant at six Mcf to one Bbl, prices have historically often been higher or substantially higher for oil than natural gas on an energy equivalent basis, although there have been periods in which they have been lower or substantially lower.

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

MMBOE. One million barrels of oil equivalent. See definition of BOE.

MMBtu. One million British Thermal Units.

MMcf. One million cubic feet.

MMcf/d. One million cubic feet per day.

MMcfe. One million cubic feet equivalent, determined using the ratio of six Mcf of natural gas to one Bbl of oil, condensate or natural gas liquids, which approximates the relative energy content of oil, condensate and natural gas liquids as compared to natural gas. See definition of Mcfe.

Net acres or net wells. The sum of the fractional working interests owned in gross acres or gross wells.

Net Revenue Interest. The operating interest used to determine the owner s share of total production.

Present value. When used with respect to oil and gas reserves, the estimated future gross revenue to be generated from the production of proved reserves, net of estimated production and future development costs, using prices and costs determined in accordance with SEC guidelines, without giving effect to nonproperty-related expenses such as general and administrative expenses, debt service and future income tax expense or to depreciation, depletion and amortization, discounted using an annual discount rate of 10%.

Production costs. Costs incurred to operate and maintain wells and related equipment and facilities, including depreciation and applicable operating costs of support equipment and facilities and other costs of operating and maintaining those wells and related equipment and facilities.

Productive well. A well that is found to be capable of producing oil or gas in sufficient quantities to justify completion as an oil or gas well.

Proved developed reserves. Reserves that are both proved and developed.

Proved reserves. Has the meaning given to such term in Rule 4-10(a)(22) of Regulation S-X, which defines proved reserves as:

The quantities of oil and gas which, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be economically producible from a given date forward, from known reservoirs, and under existing economic conditions, operating methods, and government regulations, prior to the time at which contracts providing the right to operate expire, unless evidence indicates that renewal is reasonably certain, regardless of whether deterministic or probabilistic methods are used for estimation. The project to extract the hydrocarbons must have commenced or the operator must be reasonably certain that it will commence the project within a reasonable time.

The area of a reservoir considered proved includes (i) the area identified by drilling and limited by fluid contacts, if any, and (ii) adjacent undrilled portions of the reservoir that can, with reasonable certainty, be judged to be continuous with it and to contain economically producible oil or gas on the basis of available geoscience and engineering data.

In the absence of data on fluid contacts, proved quantities in a reservoir are limited by the lowest known hydrocarbons as seen in a well penetration unless geoscience, engineering or performance data and reliable technology establish a lower contact with reasonable certainty.

Where direct observation from well penetrations has defined a highest known oil elevation and the potential exists for an associated gas cap, proved oil reserves may be assigned in the structurally higher portions of the reservoir only if geoscience, engineering or performance data and reliable technology establish the higher contact with reasonable certainty.

Reserves that can be produced economically, based on prices used to estimate reserves, through application of improved recovery techniques (including, but not limited to, fluid injection) are included in the proved classification when (i) successful testing by a pilot project in an area of the reservoir with properties no more favorable than in the reservoir as a whole, the operation of an installed program in the reservoir, or an analogous reservoir, or other evidence using reliable technology establishes the reasonable certainty of the engineering analysis on which the project or program was based and (ii) the project has been approved for development by all necessary parties and entities, including governmental entities.

Existing economic conditions include prices and costs at which economic producibility from a reservoir is to be determined. The price shall be the average price during the 12-month period prior to the ending date of the period covered by the report, determined as an unweighted arithmetic average of the first-day-of-the-month price for each month within such period, unless prices are defined by contractual arrangements, excluding escalations based upon future conditions.

Proved undeveloped reserves. Reserves that are both proved and undeveloped.

PV-10 Value. When used with respect to oil and gas reserves, present value, or PV-10 means the estimated future gross revenue to be generated from the production of proved reserves, net of estimated production and future development costs, using prices calculated as the average oil and gas price during the preceding 12-month period prior to the end of the current reporting period, (determined as the unweighted arithmetic average of prices on the first day of each month within the 12-month period) and costs in effect at the determination date, without giving effect to non-property related expenses such as general and administrative expenses, debt service and future income tax expense or to depreciation, depletion and amortization, discounted using an annual discount rate of 10%.

Reasonable certainty. If deterministic methods are used, reasonable certainty means a high degree of confidence that the quantities will be recovered. If probabilistic methods are used, there should be at least a 90% probability that the quantities actually recovered will equal or exceed the estimate. A high degree of confidence exists if the quantity is much more likely to be achieved than not, and, as changes due to increased availability of geoscience (geological, geophysical, and geochemical), engineering, and economic data are made to estimated ultimate recovery (EUR) with time, reasonably certain EUR is much more likely to increase or remain constant than to decrease.

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

Reserves. Reserves are estimated remaining quantities of oil and gas and related substances anticipated to be economically producible, as of a given date, by application of development projects to known accumulations. In addition, there must exist, or there must be a reasonable expectation that there will exist, the legal right to produce or a revenue interest in the production, installed means of delivering oil and gas or related substances to market, and all permits and financing required to implement the project.

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

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

3-D seismic data. Three-dimensional pictures of the subsurface created by collecting and measuring the intensity and timing of sound waves transmitted into the earth as they reflect back to the surface.

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

Undeveloped oil and gas reserves. Reserves of any category 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.

(i) Reserves on undrilled acreage are limited to those directly offsetting development spacing areas that are reasonably certain of production when drilled, unless evidence using reliable technology exists that establishes reasonable certainty of economic producibility, based on pricing used to estimate reserves, at greater distances.

(ii) Undrilled locations are classified as having undeveloped reserves only if a development plan has been adopted indicating that they are scheduled to be drilled within five years, unless the specific circumstances justify a longer time.

(iii) Under no circumstances are estimates for undeveloped reserves 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 projects in the same reservoir or an analogous reservoir or by other evidence using reliable technology establishing reasonable certainty.

Working interest. The operating interest that gives the owner the right to drill, produce and conduct operating activities on the property and a share of production.

Workover. Operations on a producing well to restore or increase production.

Item 1A. Risk Factors

Oil and gas prices are highly volatile, and lower oil and gas prices will negatively affect our financial position, planned capital expenditures and results of operations.

At times since July 2008, publicly quoted spot natural gas and, to a lesser extent, oil prices reached levels significantly lower than the record levels reached at that time. In the past, some oil and gas companies have reduced or curtailed production to mitigate the impact of low oil and gas prices. We have made similar decisions on selected properties in the recent past and may decide to curtail additional production as a result of a decrease in prices in the future. More recently, further decreases in natural gas prices led us to suspend or curtail drilling and other exploration activities for natural gas in the Barnett Shale, and subsequent price declines to multi-year lows may extend the period for which such exploration activities are suspended or curtailed. The decrease in natural gas prices has had a significant impact on our financial position, planned capital expenditures and results of operations. Further volatility in oil and gas prices or a prolonged period of low oil and gas prices may materially adversely affect our financial position, liquidity (including our borrowing capacity under our revolving credit facility), ability to finance planned capital expenditures and results of operations.

Our revenue, profitability, cash flow, future growth and ability to borrow funds or obtain additional capital, as well as the carrying value of our properties, are substantially dependent on prevailing prices of oil and gas. Historically, the markets for oil and gas have been volatile, and those markets are likely to continue to be volatile in the future. It is impossible to predict future oil and gas price movements with certainty. Prices for oil and gas are subject to wide fluctuation in response to relatively minor changes in the supply of and demand for oil and gas, market uncertainty and a variety of additional factors beyond our control. These factors include:

- the level of consumer product demand;
- the supply of natural gas due to increased natural gas production from resource plays;
- overall economic conditions;
- weather conditions;
- domestic and foreign governmental relations, regulations and taxes;
- the price and availability of alternative fuels;
- political conditions and unrest in oil producing regions;
- the level and price of foreign imports of oil and liquefied natural gas; and
- the ability of the members of the Organization of Petroleum Exporting Countries to agree upon and maintain production constraints and oil price controls.

Oil and gas drilling is a speculative activity and involves numerous risks and substantial and uncertain costs that could adversely affect us.

Our success will be largely dependent upon the success of our drilling program. Drilling for oil and gas involves numerous risks, including the risk that no commercially productive oil or gas reservoirs will be discovered. The cost of drilling, completing and operating wells is substantial and uncertain, and drilling operations may be curtailed, delayed or canceled as a result of a variety of factors beyond our control, including:

- unexpected or adverse drilling conditions;
- elevated pressure or irregularities in geologic formations;
- equipment failures or accidents;
- adverse weather conditions;

- compliance with governmental requirements; and

- shortages or delays in the availability of drilling rigs, crews and equipment.

Because we identify the areas desirable for drilling in certain areas from 3-D seismic data covering large areas, we may not seek to acquire an option or lease rights until after the seismic data is analyzed or until the drilling locations are also identified; in those cases, we may not be permitted to lease, drill or produce natural gas or oil from those locations.

Even if drilled, our completed wells may not produce reserves of oil or gas that are economically viable or that meet our earlier estimates of economically recoverable reserves. Our overall drilling success rate or our drilling success rate for activity within a particular project area may decline. Unsuccessful drilling activities could result in a significant decline in our production and revenues and materially harm our operations and financial position by reducing our available cash and resources. The potential for production decline rates for our wells could be greater than we expect. Because of the risks and uncertainties of our business, our future performance in exploration and drilling may not be comparable to our historical performance described in this Annual Report on Form 10-K.

We may not adhere to our proposed drilling schedule.

Our final determination of whether to drill any scheduled or budgeted wells will be dependent on a number of factors, including:

- the results of our exploration efforts and the acquisition, review and analysis of the seismic data;
- the availability of sufficient capital resources to us and the other participants for the drilling of the prospects;
- the approval of the prospects by the other participants after additional data has been compiled;
- economic and industry conditions at the time of drilling, including prevailing and anticipated prices for oil and gas and the availability and prices of drilling rigs and crews; and
- the availability of leases and permits on reasonable terms for the prospects.

Although we have identified or budgeted for numerous drilling prospects, we may not be able to lease or drill those prospects within our expected time frame or at all. Wells that are currently part of our capital plan may be based on statistical results of drilling activities in other 3-D project areas that we believe are geologically similar rather than on analysis of seismic or other data in the prospect area, in which case actual drilling and results are likely to vary, possibly materially, from those statistical results. In addition, our drilling schedule may vary from our expectations because of future uncertainties. In addition, our ability to produce oil and gas may be significantly affected by the availability and prices of hydraulic fracturing equipment and crews.

Instability in the global financial system may have impacts on our liquidity and financial condition that we currently cannot predict.

Instability in the global financial system may have a material impact on our liquidity and our financial condition, and we may ultimately face major challenges if conditions in the financial markets do not continue to improve from their lows in early 2009. Our ability to access the capital markets or borrow money may be restricted or made more expensive at a time when we would like, or need, to raise capital, which could have an adverse impact on our flexibility to react to changing economic and business conditions and on our ability to fund our operations and capital expenditures in the future. The economic situation could have an impact on our lenders or customers, causing them to fail to meet their obligations to us, and on the liquidity of our operating partners, resulting in delays in operations or their failure to make required payments. Also, market conditions could have an impact on our oil and gas derivative instruments if our counterparties are unable to perform their obligations or seek bankruptcy protection. Additionally, the current economic situation could lead to further reductions in the demand for oil and gas, or further reductions in the prices of oil and gas, or both, which could have a negative impact on our financial position, results of operations and cash flows. While the ultimate outcome and impact of the current financial situation cannot be predicted, it may have a material adverse effect on our future liquidity, results of operations and financial position.

Our reserve data and estimated discounted future net cash flows are estimates based on assumptions that may be inaccurate and are based on existing economic and operating conditions that may change in the future.

There are uncertainties inherent in estimating oil and gas reserves and their estimated value, including many factors beyond the control of the producer. The reserve data in this annual report represents only estimates. Reservoir engineering is a subjective and inexact process of estimating underground accumulations of oil and gas that cannot be measured in an exact manner and is based on assumptions that may vary considerably from actual results. Accordingly, reserve estimates may be subject to upward or downward adjustment, and actual production, revenue and expenditures with respect to our reserves likely will vary, possibly materially, from estimates. Additionally, there recently has been increased debate and disagreement over the classification of reserves, with particular focus on proved undeveloped reserves. In late 2008, the SEC adopted new rules regarding the classification of reserves. We adopted these oil and gas reserve estimation and disclosure requirements effective December 31, 2009 and, accordingly, the requirements became effective with the reserves reported in our Annual Report on Form 10-K for the year ended December 31, 2009. However, the interpretation of these rules and their applicability in different situations remain unclear in many respects. Changing interpretations of the classification standards or disagreements with our interpretations could cause us to write-down reserves.

As of December 31, 2011, approximately 59% of our proved reserves were proved undeveloped and proved nonproducing. Moreover, some of the producing wells included in our reserve reports as of December 31, 2011 had produced for a relatively short period of time as of that date. Because most of our reserve estimates are calculated using volumetric analysis, those estimates are less reliable than estimates based on a lengthy production history. Volumetric analysis involves estimating the volume of a reservoir based on the net feet of pay of the structure and an estimation of the area covered by the structure based on seismic analysis. In addition, realization or recognition of our proved undeveloped reserves will depend on our development schedule and plans. Lack of reasonable certainty with respect to development plans for proved undeveloped reserves could cause the discontinuation of the classification of these reserves as proved.

The discounted future net cash flows in this annual report are not necessarily the same as the current market value of our estimated oil and gas reserves. As required by the current requirements for oil and gas reserve estimation and disclosures, the estimated discounted future net cash flows from proved reserves are based on the average of the sales price on the first day of each month in the applicable year, with costs determined as of the date of the estimate. Actual future net cash flows also will be affected by factors such as:

- the actual prices we receive for oil and gas;
- our actual operating costs in producing oil and gas;
- the amount and timing of actual production;
- supply and demand for oil and gas;
- increases or decreases in consumption of oil and gas; and
- changes in governmental regulations or taxation.

In addition, the 10% discount factor we use when calculating discounted future net cash flows for reporting requirements in compliance with the Financial Accounting Standards Board Accounting Standards Codification Topic 932, Extractive Activities Oil and Gas may not be the most appropriate discount factor based on interest rates in effect from time to time and risks associated with us or the oil and gas industry in general.

We depend on successful exploration, development and acquisitions to maintain reserves and revenue in the future.

In general, the volume of production from oil and gas properties declines as reserves are depleted, with the rate of decline depending on reservoir characteristics. Except to the extent we conduct successful exploration and development activities or acquire properties containing proved reserves, or both, our proved reserves will decline as reserves are produced. Our future oil and gas production is, therefore, highly dependent on our level of success in finding or acquiring additional reserves. In addition, we are dependent on finding partners for our exploratory activity. To the extent that others in the industry do not have the financial resources or choose not to participate in our exploration activities, we will be adversely affected.

We participate in oil and gas leases with third parties and these third parties may not be able to fulfill their commitments to our projects.

We frequently own less than 100% of the working interest in the oil and gas leases on which we conduct operations, and other parties will own the remaining portion of the working interest. Financial risks are inherent in any operation where the cost of drilling, equipping, completing and operating wells is shared by more than one person. We could be held liable for joint activity obligations of the other working interest owners such as nonpayment of costs and liabilities arising from the actions of the other working interest owners. In addition, the current economic downturn, the credit crisis and the volatility in oil and gas prices may increase the likelihood that some of these working interest owners, particularly those that are smaller and less established, are not able to fulfill their joint activity obligations. Some of our project partners have experienced liquidity and cash flow problems. These problems may lead our partners to attempt to delay the pace of drilling or project development in order to preserve cash. A partner may be unable or unwilling to pay its share of project costs. In some cases, a partner may declare bankruptcy. In the event any of our project partners do not pay their share of such costs, we would likely have to pay those costs, and we may be unsuccessful in any efforts to recover these costs from our partners, which could materially adversely affect our financial position.

We have substantial capital requirements that, if not met, may hinder operations.

We have experienced and expect to continue to experience substantial capital needs as a result of our active exploration, development and acquisition programs. We expect that additional external financing will be required in the future to fund our growth. We may not be able to obtain additional financing, and financing under our existing revolving credit facility, our Huntington Facility or new credit facilities may not be available in the future. Even if additional capital becomes available, it may not be on terms acceptable to us. As in the past, without additional capital resources, we may be forced to limit or defer our planned oil and gas exploration and development drilling program by releasing rigs or deferring fracturing, completion and hookup of the wells to pipelines and thereby adversely affect our production, cash flow, and the recoverability and ultimate value of our oil and gas properties, in turn negatively affecting our business, financial position and results of operations.

The risks associated with our debt and the provisions of our debt agreements could adversely affect our business, financial position and results of operations.

We have demands on our cash resources, including interest expense, operating expenses and funding of our capital expenditures. Our level of debt, the demands on our cash resources and the provisions of the credit agreement governing our revolving credit facility, the Huntington Facility, and the indentures governing our 4.375% convertible senior notes due 2028 (Convertible Senior Notes) and our 8.625% Senior Notes due 2018 (Senior Notes) may have adverse consequences on our operations and financial results, including:

- placing us at a competitive disadvantage compared to our competitors that have lower debt service obligations and significantly greater operating and financial flexibility than we do;

- limiting our financial flexibility, including our ability to borrow additional funds, pay dividends, make certain investments and issue equity on favorable terms or at all;

- limiting our flexibility in planning for, and reacting to, changes in business conditions;

- increasing our interest expense on our variable rate borrowings if interest rates increase;

- requiring us to use a substantial portion of our cash flow to make debt service payments, which will reduce the funds that would otherwise be available for operations and future business opportunities;

- requiring us to modify our operations, including by curtailing portions of our drilling program, selling assets, reducing our capital expenditures, refinancing all or a portion of our existing debt or obtaining additional financing, which may be on unfavorable terms; and

- making us more vulnerable to downturns in our business or the economy.

In addition, the provisions of our revolving credit facility, the Huntington Facility and our Senior Notes place restrictions on us and certain of our subsidiaries with respect to incurring additional indebtedness and liens, making dividends and other payments to shareholders, repurchasing or redeeming our common stock, redeeming our Senior Notes, making investments, acquisitions, mergers and asset dispositions, entering into hedging transactions and other matters. Our revolving credit facility and the Huntington Facility also require that specified financial ratios be maintained. Although we currently believe that all of these financial covenants can be met with the business plan that we have put in place, our business plan and our compliance with these covenants are based on a number of assumptions, the most important of which is relatively stable oil and natural gas prices at economically sustainable levels. If the price that we receive for our oil and natural gas production deteriorates significantly from current levels it could lead to lower revenues, cash flow and earnings, which in turn could lead to a default under certain financial covenants contained in our revolving credit facility, including the covenants related to working capital and the ratios described above. Pursuant to the credit agreement governing our revolving credit facility, we are subject to financial ratio covenants which include, but are not limited to, the maintenance of the following financial covenants: (i) a Total Debt to EBITDA (each as defined in the credit agreement governing the revolving credit facility) ratio of not more than (a) 4.75 to 1.00 for the fiscal quarter ending December 31, 2011 (b) 4.25 to 1.00 for fiscal quarters ending March 31, 2012 and June 30, 2012 and (c) 4.00 to 1.00 for fiscal quarters ending September 30, 2012 and thereafter; (ii) a current ratio of not less than 1.0 to 1.0; (iii) a Senior Debt (as defined in the credit agreement governing our revolving credit facility) to EBITDA ratio of not more than 2.50 to 1.00; and (iv) an EBITDA to Interest Expense (as defined in the credit agreement governing our revolving credit facility) ratio of not less than 2.50 to 1.00. Because the calculations of the financial ratios are made as of certain dates, the financial ratios can fluctuate significantly from period to period as the amounts outstanding under our revolving credit facility are dependent on the timing of cash flows related to operations, capital expenditures, sales of oil and gas properties and securities offerings. In order to provide a further margin of comfort with regard to these financial covenants, we may seek to further reduce our capital expenditure plan, sell additional non-strategic assets or opportunistically modify or increase our derivative instruments to the extent permitted under our revolving credit facility. We cannot assure you that we will be able to successfully execute any of these strategies, or if executed, that they will be sufficient to avoid a default under our revolving credit facility if a precipitous decline in oil or natural gas prices were to occur in the future.

The borrowing base under our revolving credit facility and the borrowing base under the Huntington Facility may be reduced below the amount of borrowings outstanding under those facilities.

Under the terms of our revolving credit facility, our borrowing base is subject to redeterminations at least semi-annually based in part on prevailing oil and gas prices. A negative adjustment could occur if the estimates of future prices used by the banks in calculating the borrowing base are significantly lower than those used in the last redetermination. The next redetermination of our borrowing base is scheduled to occur in May 2012. In addition, the portion of our borrowing base made available to us is subject to the terms and covenants of the revolving credit facility including, without limitation, compliance with the ratios and other financial covenants of such facility. In the event the amount outstanding under our revolving credit facility exceeds the redetermined borrowing base, we could be forced to repay a portion of our borrowings. We may not have sufficient funds to make any required repayment. If we do not have sufficient funds and are otherwise unable to negotiate renewals of our borrowings or arrange new financing, we may have to sell a portion of our assets.

Under the terms of the Huntington Facility, availability under each of the term loan facility and the cost overrun facility are subject to borrowing bases that are generally based on consolidated cash flow and debt service projections for Carrizo UK. These borrowing bases are subject to redetermination at least semi-annually, with the next redetermination of the borrowing bases scheduled to occur in April 2012. In the event the outstanding principal balance under the Huntington Facility term loan facility and cost overrun facility exceeds the aggregate borrowing base for such facility at any time as a result of a redetermination of such facility s borrowing base, Carrizo UK will be obligated to make a payment to cure the deficiency within five business days. Carrizo UK may not have sufficient funds to make any required repayment. If Carrizo UK does not have sufficient funds and is otherwise unable to negotiate renewals of its borrowings or arrange new financing, it may default under the Huntington Facility.

We have in the past identified material weaknesses in our internal controls over financial reporting, and the identification of any material weaknesses in the future could affect our ability to ensure timely and accurate financial statements.

At the end of several periods in recent years, our management identified material weaknesses in our internal controls over financial reporting. The Public Company Accounting Oversight Board has defined a material weakness as a control deficiency, or combination of control deficiencies, that results in a reasonable possibility that a material misstatement of the annual or interim statements will not be prevented or detected on a timely basis. Accordingly, a material weakness increases the risk that the financial information we report contains material errors.

Although we have taken actions to remediate the past material weaknesses in our internal controls over financial reporting, these measures may not be sufficient to ensure that our internal controls are effective in the future. In addition, our history of material weaknesses, any future material weaknesses, or any failure to effectively address a material weakness or other control deficiency or implement required new or improved controls, or difficulties encountered in their implementation, could limit our ability to obtain financing, harm our reputation, disrupt our ability to process key components of our results of operations and financial position timely and accurately and cause us to fail to meet our reporting obligations under rules of the SEC, NASDAQ and our various debt arrangements.

We have limited experience drilling wells in the Niobrara Formation and in the Eagle Ford Shale and less information regarding reserves and decline rates in these shale formations than in some other areas of our operations.

We have limited exploration and development experience in the Niobrara Formation and in the Eagle Ford Shale. We have participated in the drilling of 11 horizontal gross (7.6 net) wells in the Niobrara Formation and have participated in 35 horizontal gross (28 net) wells in the Eagle Ford Shale. Other operators in these areas have significantly more experience in the drilling of wells, including the drilling of horizontal wells. As a result, we have less information with respect to the ultimate recoverable reserves, the production decline rate and other matters relating to the exploration, drilling and development of the Niobrara Formation and the Eagle Ford Shale than we have in some other areas in which we operate.

We have limited experience drilling wells in the Marcellus Shale and less information regarding reserves and decline rates in the Marcellus Shale than in some other areas of our operations. We may face difficulties in securing and operating under authorizations and permits to drill and/or operate our Marcellus Shale wells.

We have limited exploration and development experience in the Marcellus Shale. As of December 31, 2011, we have participated or are participating in the drilling of 50 gross (14.1 net) wells in the Marcellus Shale area. Other operators in the Appalachian Basin have significantly more experience in the drilling of Marcellus Shale wells, including the drilling of horizontal wells. As a result, we have less information with respect to the ultimate recoverable reserves and the production decline rate in the Marcellus Shale than we have in some other areas in which we operate. Moreover, the recent growth in exploration in the Marcellus Shale has drawn intense scrutiny from environmental and community interest groups, regulatory agencies and other governmental entities. As a result, we may face significant opposition to, or increased regulation of, our operations that may make it difficult or impossible to obtain permits and other needed authorizations to operate, result in operational delays, or otherwise make operating more costly or difficult than operating elsewhere.

We have no experience drilling wells in the Utica Shale and less information regarding reserves and decline rates in this shale formation than in some other areas of our operations.

We have no exploration experience and no development experience in the Utica Shale. We have not participated in the drilling of any wells in this area. Other operators in this area have significantly more experience in the drilling of wells, including the drilling of horizontal wells. As a result, we have less information with respect to the ultimate recoverable reserves, the production decline rate and other matters relating to the exploration, drilling and development of the Utica Shale than we have in some other areas in which we operate.

If we are unable to acquire adequate supplies of water for our drilling operations or are unable to dispose of the water we use at a reasonable cost and within applicable environmental rules, our ability to produce gas commercially and in commercial quantities could be impaired.

We use a substantial amount of water in our drilling operations. Our inability to locate sufficient amounts of water, or treat and dispose of water after drilling, could adversely impact our operations. Moreover, the imposition of new environmental initiatives and regulations could include restrictions on our ability to conduct certain operations such as hydraulic fracturing or disposal of waste, including, but not limited to, produced water, drilling fluids and other wastes associated with the exploration, development or production of natural gas. Furthermore, future environmental regulations and permit requirements governing the withdrawal, storage and use of surface water or groundwater necessary for hydraulic fracturing of wells could increase operating costs and cause delays, interruptions or termination of operations, the extent of which cannot be predicted, all of which could have an adverse effect on our operations and financial performance.

We may not increase our acreage positions in areas with exposure to oil, condensate and natural gas liquids.

If we are unable to increase our acreage positions in the Eagle Ford Shale, the Niobrara Formation or the Utica Shale, this may detract from our efforts to realize our growth strategy in crude oil and liquids-rich plays. Additionally, we may be unable to find or consummate other opportunities in these areas or in other areas with similar exposure to oil, condensate and natural gas liquids on similar terms or at all.

A substantial portion of our reserves is located in an urban area, which could increase our costs of development and delay production.

Our current primary core gas producing area is located in largely urban portions of the Barnett Shale, which could disproportionately expose us to operational and regulatory risk in that area. At December 31, 2011, approximately 70% of our proved reserves and approximately 79% of our then current production were located in the Barnett Shale. The core of the Barnett Shale is located in and around the greater Dallas-Fort Worth, Texas metropolitan area and much of our operations are within the city limits of various municipalities in that region, such as Arlington and Mansfield, Texas. In such urban or other populated areas, we may incur additional expenses, including expenses relating to mitigation of noise, odor and light that may be emitted in our operations, expenses related to the appearance of our facilities and limitations regarding when and how we can operate. The process of obtaining permits for drilling or for gathering lines to move our natural gas to market in such areas may be more time consuming and costly than in more rural areas. In addition, we may experience a higher rate of litigation or increased insurance and other costs related to our operations or facilities in such highly populated areas.

We face strong competition from other oil and gas companies.

We encounter competition from other oil and gas companies in all areas of our operations, including the acquisition of exploratory prospects and proven properties. Our competitors include major integrated oil and gas companies and numerous independent oil and gas companies, individuals and drilling and income programs. Many of our competitors are large, well-established companies that have been engaged in the oil and gas business much longer than we have and possess substantially larger operating staffs and greater capital resources than we do. These companies may be able to pay more for exploratory projects and productive oil and gas properties and may be able to define, evaluate, bid for and purchase a greater number of properties and prospects than our financial or human resources permit. In addition, these companies may be able to expend greater resources on the existing and changing technologies that we believe are and will be increasingly important to attaining success in the industry. Such competitors may also be in a better position to secure oilfield services and equipment on a timely basis or on favorable terms. We may not be able to conduct our operations, evaluate and select suitable properties and consummate transactions successfully in this highly competitive environment.

We may not be able to keep pace with technological developments in our industry.

The oil and gas industry is characterized by rapid and significant technological advancements and introductions of new products and services using new technologies. As others use or develop new technologies, we may be placed at a competitive disadvantage, and competitive pressures may force us to implement those new technologies at substantial cost. In addition, other oil and gas companies may have greater financial, technical and personnel resources that allow them to enjoy technological advantages and may in the future allow them to implement new technologies before we can. We may not be able to respond to these competitive pressures and implement new technologies on a timely basis or at an acceptable cost. If one or more of the technologies we use now or in the future were to become obsolete or if we are unable to use the most advanced commercially available technology, our business, financial condition and results of operations could be materially adversely affected.

We are subject to various environmental risks and governmental regulations, including those relating to benzene emissions and hydraulic fracturing, and future regulations may be more stringent.

Oil and gas operations are subject to various federal, state, local and foreign laws and government regulations that may change from time to time. Matters subject to regulation include discharge permits for drilling operations, plug and abandonment bonds, reports concerning operations, the spacing of wells, unitization and pooling of properties and taxation. From time to time, regulatory agencies have imposed price controls and limitations on production by restricting the rate of flow of oil and gas wells below actual production capacity in order to conserve supplies of oil and gas. Other federal, state, local and foreign laws and regulations relating primarily to the protection of human health and the environment apply to the development, production, handling, storage, transportation and disposal of oil and gas, by-products thereof and other substances and materials produced or used in connection with oil and gas operations, including drilling fluids and wastewater. In addition, we may incur costs arising out of property damage, including environmental damage caused by previous owners or operators of property we purchase or lease or relating to third party sites, or injuries to employees and other persons. As a result, we may incur substantial liabilities to third parties or governmental entities and may be required to incur substantial remediation costs. We also are subject to changing and extensive tax laws, the effects of which cannot be predicted. Compliance with existing, new or modified laws and regulations could result in substantial costs, delay our operations or otherwise have a material adverse effect on our business, financial position and results of operations.

Moreover, changes in environmental laws and regulations occur frequently and such laws and regulations tend to become more stringent over time. Stricter laws, regulations or enforcement policies could significantly increase our compliance costs and negatively impact our production and operations. For example, the Texas Commission on Environmental Quality has finalized revisions to certain air permit programs that significantly increase the air permitting requirements for new and certain existing oil and gas production and gathering sites for 23 counties in the Barnett Shale production area. The final rule established new emissions standards for a broad array of equipment at our drillsites, including engines. Additionally, on July 28, 2011, the EPA issued proposed rules that would subject all oil and gas operations (production, processing, transmission, storage and distribution) to regulation under the New Source Performance Standards (NSPS) and National Emission Standards for Hazardous Air Pollutants (NESHAPS) programs. The EPA proposed rules also include NSPS standards for completions of hydraulically fractured gas wells. These standards include the reduced emission completion techniques developed in the EPA s Natural Gas STAR program along with the pit flaring of gas not sent to the gathering line. The standards would be applicable to newly drilled and fractured wells as well as existing wells that are refractured. Further, the proposed regulations under NESHAPS include maximum achievable control technology (MACT) standards for those glycol dehydrators and storage vessels at major sources of hazardous air pollutants not currently subject to MACT standards. We are currently evaluating the effect these proposed rules could have on our business. Final action on the proposed rules is expected no later than April 3, 2012. If these or other initiatives result in an increase in regulation, it could increase our costs or reduce our production, which could have a material adverse effect on our results of operations and cash flows.

Hydraulic fracturing is an important and commonly used process in the completion of oil and gas wells, particularly in unconventional resource plays like the Barnett Shale, the Marcellus Shale, the Eagle Ford Shale and the Niobrara Formation. Hydraulic fracturing involves the injection of water, sand and chemicals under pressure into rock formations to stimulate gas production. The U.S. Congress has considered legislation to subject hydraulic fracturing operations to federal regulation and to require the disclosure of chemicals used by us and others in the oil and gas industry in the hydraulic fracturing process. The EPA has recently asserted federal regulatory authority over hydraulic fracturing involving diesel under the federal Safe Drinking Water Act and is developing guidance documents related to this newly asserted regulatory authority. Additionally, the EPA has commenced a comprehensive research study to investigate the potential adverse environmental impacts of hydraulic fracturing, including on water quality and public health. The initial EPA study results are expected to be available in late 2012 with final results available in 2014. Further, the EPA announced on October 20, 2011 that it is launching a study of wastewater resulting from hydraulic fracturing activities and currently plans to propose pretreatment regulations by 2014. Moreover, on November 23, 2011, the EPA announced that it was granting in part a petition to initial rulemaking under the Toxic Substances Control Act, relating to chemical substances and mixtures used in oil and gas exploration and production. The Department of Energy, at the direction of the President, is also studying hydraulic fracturing in order to provide recommendations and identify best practices and other steps to enhance companies safety and environmental performance of hydraulic fracturing.

At the state level, the New York legislature has approved a temporary moratorium on drilling involving hydraulic fracturing and the New York State Department of Environmental Conservation has ceased issuing exploration and production drilling permits, pending completion of an environmental impact statement regarding hydraulic fracturing. Pennsylvania has adopted a variety of regulations since 2010 limiting how and where hydraulic fracturing can be performed in the state, including the adoption of upgraded well construction and casing standards, upgraded cement standards and new recordkeeping requirements. Some municipalities in the state have adopted or are considering adopting bans on drilling, including areas in which we operate, and the Governor of Pennsylvania has instituted a moratorium on leasing state forest land for new gas drilling. Further, in July 2011, the Pennsylvania Governor s Marcellus Shale Advisory Commission released its report setting forth 96 recommendations on a variety of issues related to natural gas development in Pennsylvania. These recommendations are related to infrastructure; public health, safety, and environmental protection; local impact and emergency response; and economic and workforce development. The Marcellus Shale Advisory Commission made the most recommendations in the area of public health, safety and environmental protection, including doubling penalties authorized for violations of the Oil and Gas Act; increasing bonding requirements; authorizing a state agency to suspend, revoke, or deny permits on a quicker timeframe for violations or failure to correct violations; expanding a well operator s presumed liability for impaired water quality; amending well stimulation and completion reporting requirements to require disclosure of hazardous chemicals used in fracturing; and other issues related to fracturing operations. Some or all of these recommendations have been incorporated into proposed legislation, will likely be acted upon and may result in the adoption of new laws and regulations governing shale gas development in the Marcellus Shale in Pennsylvania that could result in substantial changes in the way natural gas activities are conducted in the area.

At the international level, the U.K. and EU Parliaments have each in the past discussed implementing a drilling moratorium in the U.K. North Sea. We use hydraulic fracturing extensively and any increased federal, state, local, foreign or international regulation of hydraulic fracturing or offshore drilling, including legislation and regulation in the states of New York and Pennsylvania, could reduce the volumes of oil and gas that we can economically recover, which could materially and adversely affect our revenues and results of operations.

President Obama s 2012 Fiscal Year Budget proposals, and certain legislation introduced in the U.S. Congress, if enacted into law, would make significant changes to United States tax laws, including the elimination of certain key U.S. federal income tax incentives currently available to oil and gas exploration and production companies. These or any other similar changes in U.S. federal income tax laws could defer or eliminate certain tax deductions that are currently available with respect to oil and gas exploration and development, and any such change could negatively affect our financial position and results of operations.

Climate change and climate change legislation and regulatory initiatives could result in increased operating costs and decreased demand for the oil and gas that we produce.

There is increasing attention in the United States and worldwide being paid to the issue of climate change and the contributing effect of GHG emissions. The EPA has issued a final rule to address permitting of GHG emissions from stationary sources. In addition, the U.S. Congress has considered a number of legislative proposals to restrict GHG emissions and more than 20 states, either individually or as part of regional initiatives, have begun taking actions to control and/or reduce GHG emissions. While it is not possible at this time to predict how regulation that may be enacted to address GHG emissions would impact our business, the modification of existing laws or regulations or the adoption of new laws or regulations curtailing oil and gas exploration in the areas of the United States or the North Sea in which we operate could materially and adversely affect our operations by limiting drilling opportunities or imposing materially increased costs. In addition, existing or new laws, regulations or treaties (including incentives to conserve energy or use alternative energy sources) could have a negative impact on our business if such incentives reduce demand for natural gas. See Item 1. Business Additional Oil and Gas Disclosures Regulation; Global Climate Change for additional information.

Our onshore and offshore operations are subject to various operating and other casualty risks that could result in liability exposure or the loss of production and revenues.

The oil and gas business involves operating hazards such as:

- well blowouts;
- mechanical failures;
- explosions;
- pipe or cement failures and casing collapses, which could release natural gas, oil, drilling fluids or hydraulic fracturing fluids;
- uncontrollable flows of oil, natural gas or well fluids;
- fires;
- geologic formations with abnormal pressures;
- handling and disposing of materials, including drilling fluids and hydraulic fracturing fluids;
- pipeline ruptures or spills;
- releases of toxic gases; and
- other environmental hazards and risks.

Any of these hazards and risks can result in the loss of hydrocarbons, environmental pollution, personal injury claims and other damage to our properties and the property of others.

Offshore operations are subject to a variety of operating risks in addition to the hazards described above, such as capsizing, collisions and damage or loss from adverse weather conditions. Additionally, the occurrence of other events such as blowouts and oil spills in marine environments can make containment and remediation more difficult and costly than on land. These conditions can and have caused substantial damage to facilities and interrupted production. Our operations in the U.K. North Sea are dependent upon the availability, proximity and capacity of pipelines, natural gas gathering systems and processing facilities and a floating production storage and offloading vessel. Any significant change affecting these infrastructure facilities or vessel could materially harm our business. We deliver crude oil and natural gas through gathering systems and pipelines that we do not own. These facilities or vessel may be temporarily unavailable due to adverse weather conditions or operational issues or may not be available to us in the future. As a result, we could incur substantial liabilities or experience reductions in revenue that could reduce or eliminate the funds available for our exploration and development programs and acquisitions, or result in the loss of properties. Additionally, offshore operations generally involve increased costs and more expansive regulatory requirements as compared to onshore operations.

We may not have enough insurance to cover all of the risks we face.

We maintain insurance against losses and liabilities in accordance with customary industry practices and in amounts that management believes to be prudent; however, insurance against all operational risks is not available to us. We do not carry business interruption insurance. We may elect not to carry insurance if management believes that the cost of available insurance is excessive relative to the risks presented. In addition, losses could occur for uninsured risks or in amounts in excess of existing insurance coverage. We cannot insure fully against pollution and environmental risks. We cannot assure you that we will be able to maintain adequate insurance in the future at rates we consider reasonable or that any particular types of coverage will be available. The occurrence of an event not fully covered by insurance could have a material adverse effect on our financial position and results of operations.

We conduct a substantial portion of our operations through joint ventures, which subject us to additional risks that could have a material adverse effect on the success of these operations, our financial position and our results of operations.

We conduct a substantial portion of our operations through joint ventures with third parties, including Avista and its affiliates, GAIL, Reliance and an affiliate of Sumitomo Corporation. We may also enter into other joint venture arrangements in the future. These third parties may have obligations that are important to the success of the joint venture, such as the obligation to pay substantial carried costs pertaining to the joint venture and to pay their share of capital and other costs of the joint venture. The performance of these third party obligations, including the ability of the third parties to satisfy their obligations under these arrangements, is outside our control. If these parties do not satisfy their obligations under these arrangements, our business may be adversely affected.

Our joint venture arrangements may involve risks not otherwise present when exploring and developing properties directly, including, for example:

- our joint venture partners may share certain approval rights over major decisions;
- our joint venture partners may not pay their share of the joint venture s obligations, leaving us liable for their shares of joint venture liabilities;
- we may incur liabilities as a result of an action taken by our joint venture partners;
- our joint venture partners may be in a position to take actions contrary to our instructions or requests or contrary to our policies or objectives; and
- disputes between us and our joint venture partners may result in delays, litigation or operational impasses.

The risks described above or the failure to continue our joint ventures or to resolve disagreements with our joint venture partners could adversely affect our ability to transact the business that is the subject of such joint venture, which would in turn negatively affect our financial condition and results of operations.

Our joint venture with Reliance contemplates that we will make significant capital expenditures and subjects us to certain legal and financial terms that could adversely affect us.

In 2010, we completed the sale to Reliance of 20% of our interests in oil and gas properties in parts of Pennsylvania in the Marcellus Shale for approximately $13.1 million in cash and a carry commitment by Reliance to pay 75% of certain of our future development costs up to approximately $52.0 million. At that time, we entered into agreements with Reliance to form a new joint venture with respect to the interests being purchased by Reliance from us and ACP II such that we generally retained a 40% working interest in the acreage and Reliance generally owns a 60% working interest.

The agreements under which we formed this joint venture subject us to various risks, limit the actions we may take with respect to our properties and require us to grant rights to Reliance that could limit our ability to benefit fully from future positive developments. The joint venture requires us to make significant capital expenditures. If we do not timely meet our financial commitments or otherwise do not comply with our joint venture agreements, our rights to participate, exercise operator rights or otherwise influence or benefit from the joint venture will be adversely affected.

Reliance s obligation to fund the carry commitment expires with respect to any portion of the carry commitment not utilized by September 10, 2013, subject to certain extensions. We have agreed to various restrictions on our ability to transfer our properties covered by the joint venture. Additionally, following the expiration of the carry commitment, we are subject to a mutual right of first offer on direct and indirect property transfers for the remainder of a ten-year development period (through September 2020), subject to specified exceptions. We have also granted an option to Reliance to purchase a 60% (as adjusted over time) share of acreage in the area of mutual interest purchased directly or indirectly by us after the closing. This option, which covers substantially all of Pennsylvania, is exercisable at our cost plus, in the case of direct property sales, a specified premium, and is subject to specified exceptions. We serve as operator of the properties covered by this joint venture, with Reliance having the right to assume operatorship of 60% of the undeveloped acreage in portions of central Pennsylvania beginning as early as September

2011 and extending through September 2014, to purchase all of our 40% interest in such acreage at a specified price. Operations under the joint venture will generally be required to conform to a budget approved by an operating committee that includes representatives of both parties, subject to exceptions, including those for sole risk operations and in the event of defaults by the parties. The parties have also generally agreed until 2013 to forego the ability to conduct sole risk operations and to certain other limits to such operations thereafter. Reliance has substantially greater financial resources than we have and we may not be able to secure the funding necessary to participate in operations Reliance proposes, thereby reducing our ability to benefit from the joint venture.

We cannot control the activities on properties we do not operate.

We do not operate all of the properties in which we have an interest. As a result, we have limited ability to exercise influence over, and control the risks associated with, 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 or could create liability for us for the operator s failure to properly maintain the well and facilities and to adhere to applicable safety and environmental standards. With respect to properties that we do not operate:

- the operator could refuse to initiate exploration or development projects;
- if we proceed with any of those projects the operator has refused to initiate, we may not receive any funding from the operator with respect to that project;
- the operator may initiate exploration or development projects on a different schedule than we would prefer;
- the operator may propose greater capital expenditures than we wish, including expenditures to drill more wells or build more facilities on a project than we have funds for, which may mean that we cannot participate in those projects or participate in a substantial amount of the revenues from those projects; and
- the operator may not have sufficient expertise or resources.

Any of these events could significantly and adversely affect our anticipated exploration and development activities.

If our access to markets is restricted, it could negatively impact our production, our income and ultimately our ability to retain our leases. Our ability to sell oil and natural gas and/or receive market prices for our oil and natural gas may be adversely affected by pipeline and gathering system capacity constraints.

Market conditions or the unavailability of satisfactory oil and gas transportation arrangements may hinder our access to oil and gas markets or delay our production. The availability of a ready market for our oil and gas production depends on a number of factors, including the demand for and supply of oil and gas 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 oil or gas 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, possibly causing us to lose a lease due to lack of production. There is currently only limited pipeline and gathering system capacity in the Marcellus Shale.

Historically, we have generally delivered our oil and gas production through gathering systems and pipelines that we do not own under interruptible or short-term transportation agreements. Under the interruptible transportation agreements, the transportation of our oil and gas production may be interrupted due to capacity constraints on the applicable system, for maintenance or repair of the system, or for other reasons as dictated by the particular agreements. Due to the lack of available pipeline capacity in the Eagle Ford Shale and the Marcellus Shale, we have entered into firm transportation agreements for a portion of our production in the Eagle Ford Shale and Marcellus Shale in order to assure our ability, and that of our purchasers, to successfully market the oil and gas that we produce. We may also enter into firm transportation arrangements for additional production in the future. These firm transportation agreements may be more costly than interruptible or short-term transportation agreements.

If production in the Marcellus Shale by oil and gas companies continues to expand, the amount of natural gas being produced by us and others could exceed the capacity of the various gathering and intrastate or interstate transportation pipelines currently available in these areas. If this occurs, it will be necessary for new pipelines and gathering systems to be built. Because of the current economic climate, certain pipeline projects that are planned for the Marcellus Shale may not occur for lack of financing. In addition, capital constraints could limit our ability to build intrastate gathering systems necessary to transport our gas to interstate pipelines. In such event, we might have to shut in our wells awaiting a pipeline connection or capacity and/or sell natural gas production at significantly lower prices than those we currently project, which could materially and adversely affect our results of operations.

A portion of our oil and gas production in any region may be interrupted, or shut in, from time to time for numerous reasons, including as a result of weather conditions, accidents, loss of pipeline or gathering system access, field labor issues or strikes, or we might voluntarily curtail production in response to market conditions. If a substantial amount of our production is interrupted at the same time, it could temporarily adversely affect our cash flow.

Our future acquisitions may yield revenues or production that varies significantly from our projections.

In acquiring producing properties, we assess the recoverable reserves, future oil and gas prices, operating costs, potential liabilities and other factors relating to the properties. Our assessments are necessarily inexact and their accuracy is inherently uncertain. Our review of a subject property in connection with our acquisition assessment will not reveal all existing or potential problems or permit us to become sufficiently familiar with the property to assess fully its deficiencies and capabilities. We may not inspect every well, and we may not be able to observe structural and environmental problems even when we do inspect a well. If problems are identified, the seller may be unwilling or unable to provide effective contractual protection against all or part of those problems. Any acquisition of property interests may not be economically successful, and unsuccessful acquisitions may have a material adverse effect on our financial position and future results of operations.

Our business may suffer if we lose key personnel.

We depend to a large extent on the services of certain key management personnel, including our executive officers and other key employees, the loss of any of whom could have a material adverse effect on our operations. We have entered into employment agreements with many of our key employees as a way to assist in retaining their services and motivating their performance. We do not maintain key-man life insurance with respect to any of our employees. Our success will also be dependent on our ability to continue to employ and retain skilled technical personnel.

We may experience difficulty in achieving and managing future growth.

We have experienced growth in the past primarily through the expansion of our drilling program. Future growth may place strains on our financial, technical, operational and administrative resources and cause us to rely more on project partners and independent contractors, possibly negatively affecting our financial position and results of operations. Our ability to grow will depend on a number of factors, including:

- our ability to obtain leases or options on properties, including those for which we have 3-D seismic data;
- our ability to acquire additional 3-D seismic data;
- our ability to identify and acquire new exploratory prospects;
- our ability to develop existing prospects;
- our ability to continue to retain and attract skilled personnel;
- our ability to maintain or enter into new relationships with project partners and independent contractors;
- the results of our drilling program;

hydrocarbon prices; and

our access to capital.

We may not be successful in upgrading our technical, operations and administrative resources or in increasing our ability to internally provide certain of the services currently provided by outside sources, and we may not be able to maintain or enter into new relationships with project partners and independent contractors. Our inability to achieve or manage growth may adversely affect our financial position and results of operations.

We may continue to enter into derivative transactions to manage the price risks associated with our production. Our derivative transactions may result in our making cash payments or prevent us from benefiting from increases in prices for oil and gas.

Because oil and gas prices are unstable, we periodically enter into price-risk-management transactions such as fixed-rate swaps, costless collars, puts, calls and basis differential swaps to reduce our exposure to price declines associated with a portion of our oil and gas production and thereby to achieve a more predictable cash flow. The use of these arrangements limits our ability to benefit from increases in the prices of oil and gas. Our derivative arrangements may apply to only a portion of our production, thereby providing only partial protection against declines in oil and gas prices. These arrangements may expose us to the risk of financial loss in certain circumstances, including instances in which production is less than expected, our customers fail to purchase contracted quantities of oil and gas or a sudden, unexpected event materially impacts oil or gas prices. In addition, the counterparties under our derivatives contracts may fail to fulfill their contractual obligations to us.

Periods of high demand for field services and equipment and the ability of suppliers to meet that demand may limit our ability to drill and produce our oil and gas properties.

During periods when oil and gas prices are relatively high, well service providers and related equipment and personnel may be in short supply. These shortages can cause escalating prices, delays in drilling and other exploration activities and the possibility of poor services coupled with potential damage to downhole reservoirs and personnel injuries. Such pressures may increase the actual cost of services, extend the time to secure such services and add costs for damages due to any accidents sustained from the overuse of equipment and inexperienced personnel.

We may record impairments of oil and gas properties that would reduce our shareholders equity.

We use the full cost method of accounting for our oil and gas properties. Accordingly, we capitalize all productive and nonproductive costs directly associated with property acquisition, exploration and development activities to cost centers established on a country-by-country basis. Under the full cost method, the capitalized cost of oil and gas properties, less accumulated amortization and related deferred income taxes may not exceed the cost center ceiling which is equal to the sum of the present value of estimated future net revenues from proved reserves, less estimated future expenditures to be incurred in developing and producing the proved reserves computed using a discount factor of 10%, plus the costs of properties not subject to amortization, plus the lower of the cost or estimated fair value of unproved properties included in the costs being amortized, less related income tax effects. If the net capitalized costs exceed the cost center ceiling, we recognize the excess as an impairment of oil and gas properties. This impairment does not impact cash flows from operating activities but does reduce earnings and our shareholders equity. The risk that we will be required to recognize impairments of our oil and gas properties increases during periods of low oil and/or gas prices. In addition, impairments would occur if we were to experience sufficient downward adjustments to our estimated proved reserves or the present value of estimated future net revenues, as further discussed under Our reserve data and estimated discounted future net cash flows are estimates based on assumptions that may be inaccurate and are based on existing economic and operating conditions that may change in the future. An impairment recognized in one period may not be reversed in a subsequent period even if higher oil and gas prices increase the cost center ceiling applicable to the subsequent period. We recorded non-cash impairments of oil and gas properties at the end of the first quarter of 2009 and the end of 2009 with respect to our U.S. cost center and at the end of the second quarter of 2010 with respect to our U.K. cost center. We could incur additional impairments of oil and gas properties in the future, particularly as a result of a decline in oil and/or gas prices.

We could lose our ability to use net operating loss carryforwards that we have accumulated over the years.

Our ability to utilize U.S. net operating loss (NOL) carryforwards to reduce future taxable income is subject to various limitations under the Internal Revenue Code of 1986, as amended (the Code). The utilization of such carryforwards may be limited upon the occurrence of certain ownership changes, including the purchase or sale of our stock by 5% shareholders and our offering of stock during any three-year period resulting in an aggregate change of more than 50% in our beneficial ownership. In the event of an ownership change, Section 382 of the Code imposes an annual limitation on the amount of our taxable income that can be offset by these carryforwards. The limitation is generally equal to the product of (a) the fair market value of our equity multiplied by (b) a percentage approximately equivalent to the yield on long-term tax exempt bonds during the month in which an ownership change occurs. In addition, the limitation is increased if there are recognized built-in gains during any post-change year, but only to the extent of any net unrealized built-in gains inherent in the assets sold. As of December 31, 2011, we believe an ownership change occurred in

February 2005 with an annual limitation of approximately $12.6 million. Moreover, based on our knowledge of our shareholder ownership, we do not believe that an ownership change has occurred since February 2005 that would further limit our ability to utilize our U.S. NOLs. Because our pre-change NOLs are approximately $9.8 million, we do not believe we have a Section 382 limitation on our ability to utilize our U.S. NOL carryforwards as of December 31, 2011. Future equity transactions involving us or our 5% shareholders (including, potentially, relatively small transactions and transactions beyond our control) could cause further ownership changes and therefore a limitation on the annual utilization of our U.S. NOLs.

Enactment of proposed impact fees on natural gas wells could adversely impact our results of operations and the economic viability of exploiting natural gas drilling and production opportunities in Pennsylvania.

Legislation has been enacted in Pennsylvania, that authorizes counties to impose fees on certain natural gas wells in Pennsylvania. If a county elects to impose a fee, the fee will apply to any unconventional gas well, which is generally defined as a well using hydraulic fracture treatments or multilateral well bores. Any county that elects not to impose the fee can be overruled by the municipalities within that county. The fee would be imposed over a fifteen year period, starting with the year the well is actually drilled and declining thereafter, and is based on natural gas prices and the Consumer Price Index. Unconventional gas wells drilled before the fee is imposed would still be subject to the fee and, for purposes of calculating the amount of the fee, will be considered to have been drilled in the calendar year prior to the imposition of the fee. A substantial portion of our Marcellus Shale acreage and a portion of our Utica Shale acreage is located in the Commonwealth of Pennsylvania. To the extent such fees are ultimately enacted by counties in which we now or may in the future operate, or if Pennsylvania adopts severance taxes or additional fees, such actions could adversely impact our results of operations and the economic viability of exploiting natural gas drilling and production opportunities in Pennsylvania.

We may incur losses as a result of title deficiencies.

We purchase working and revenue interests in the oil and gas leasehold interests upon which we will perform our exploration activities from third parties or directly from the mineral fee owners. The existence of a material title deficiency can render a lease worthless and can adversely affect our results of operations and financial condition. Title insurance covering mineral leaseholds is not generally available and, in all instances, we forego the expense of retaining lawyers to examine the title to the mineral interest to be placed under lease or already placed under lease until the drilling block is assembled and ready to be drilled. Even then, particularly in urban settings, the cost of performing detailed title work can be expensive. We may choose to forgo detailed title examination by title lawyers on a portion of the mineral leases that we place in a drilling unit or conduct less title work than we have traditionally performed. As is customary in our industry, we generally rely upon the judgment of oil and gas lease brokers or independent landmen who perform the field work in examining records in the appropriate governmental offices and abstract facilities before attempting to acquire or place under lease a specific mineral interest and before drilling a well on a leased tract. We, in some cases, perform curative work to correct deficiencies in the marketability or adequacy of the title to us. The work might include obtaining affidavits of heirship or causing an estate to be administered. In cases involving more serious title problems, the amount paid for affected oil and gas leases can be generally lost, and the target area can become undrillable. The failure of title may not be discovered until after a well is drilled, in which case we may lose the lease and the right to produce all or a portion of the minerals under the property.

We have risks associated with our foreign operations.

We currently have international activities and we continue to evaluate and pursue new opportunities for international expansion in select areas. Ownership of property interests and production operations in areas outside the United States is subject to the various risks inherent in foreign operations. These risks may include:

- currency restrictions and exchange rate fluctuations;
- loss of revenue, property and equipment as a result of expropriation, nationalization, war or insurrection;
- increases in taxes and governmental royalties;
- renegotiation of contracts with governmental entities and quasi-governmental agencies;

changes in laws and policies governing operations of foreign-based companies;

labor problems; and

other uncertainties arising out of foreign government sovereignty over our international operations.

Our international operations also may be adversely affected by the laws and policies of the United States affecting foreign trade, taxation and investment. In addition, if a dispute arises with respect to our foreign operations, we may be subject to the exclusive jurisdiction of foreign courts or may not be successful in subjecting foreign persons to the jurisdiction of the courts of the United States.

A portion of our operations is exposed to the additional risk of tropical weather disturbances.

A portion of our production and reserves is located onshore South Louisiana and Texas. Operations in this area are subject to tropical weather disturbances. Some of these disturbances can be severe enough to cause substantial damage to facilities and possibly interrupt production. For example, some of our wells in the Gulf Coast were shut in following Hurricanes Katrina and Rita in 2005 and Hurricanes Gustav and Ike in 2008. In accordance with customary industry practices, we maintain insurance against some, but not all, of these risks. See We may not have enough insurance to cover all of the risks we face.

The threat and impact of terrorist attacks, cyber attacks or similar hostilities may adversely impact our operations.

We cannot assess the extent of either the threat or the potential impact of future terrorist attacks on the energy industry in general, and on us in particular, either in the short-term or in the long-term. Uncertainty surrounding such hostilities may affect our operations in unpredictable ways, including the possibility that infrastructure facilities, including pipelines and gathering systems, production facilities, processing plants and refineries, could be targets of, or indirect casualties of, an act of terror, a cyber attack or electronic security breach, or an act of war.

Item 1B. Unresolved Staff Comments

None.

Item 2. Properties

Information regarding our properties is included in Item 1. Business above and in Note 4. Property and Equipment, Net of the notes to our consolidated financial statements included in Item 8. Financial Statements and Supplementary Data, which information is incorporated herein by reference.

Item 3. Legal Proceedings

From time to time, we are party to certain legal actions and claims arising in the ordinary course of business. While the outcome of these events cannot be predicted with certainty, management does not expect these matters to have a materially adverse effect on our financial position or results of operations.

Item 4. Mine Safety Disclosures

Not applicable.

PART II

Item 5. Market for Registrant s Common Stock, Related Shareholder Matters and Issuer Purchases of Equity Securities

Our common stock, par value $0.01 per share, trades on the NASDAQ Global Select Market under the symbol CRZO. The following table sets forth the high and low sales prices per share of our common stock on the NASDAQ Global Select Market for the periods indicated.

	High	Low
2010		
First Quarter	$ 28.85	$ 21.17
Second Quarter	25.23	15.20
Third Quarter	24.25	14.81
Fourth Quarter	34.78	22.82
2011		
First Quarter	$ 39.34	$ 28.71
Second Quarter	42.72	32.47
Third Quarter	44.17	20.95
Fourth Quarter	30.00	18.02

The closing market price of our common stock on February 27, 2012 was $27.62 per share. As of February 27, 2012, there were an estimated 144 owners of record of our common stock.

We have not paid any dividends on our common stock in the past and do not intend to pay such dividends in the foreseeable future. We currently intend to retain any earnings for the future operation and development of our business, including exploration, development and acquisition activities. Our revolving credit facility restricts our ability to pay dividends. See Item 7. Management s Discussion and Analysis of Financial Condition and Results of Operations Liquidity and Capital Resources.

The following graph presents a comparison of the yearly percentage change in the cumulative total return on our Common Stock over the period from December 31, 2006 to December 31, 2011, with the cumulative total return of the S&P 500 Index and the American Stock Exchange (AMEX) Natural Resources Industry Index of publicly traded companies over the same period. The graph assumes that $100 was invested on December 31, 2006 in our common stock at the closing market price at the beginning of this period and in each of the other two indices and the reinvestment of all dividends, if any.

The graph is presented in accordance with requirements of the SEC. Shareholders are cautioned against drawing any conclusions from the data contained therein, as past results are not necessarily indicative of future financial performance.

	S&P	AMEX	COGI
December 31, 2006	100	100	100
December 31, 2007	104	128	189
December 31, 2008	64	65	55
December 31, 2009	79	90	91
December 31, 2010	89	116	119
December 31, 2011	89	103	91

Pursuant to SEC rules, the foregoing graph is not deemed filed with the SEC.

We made no repurchases of our common stock in the fourth quarter of 2011.

As described in Item 7. Management s Discussion and Analysis of Financial Condition and Results of Operations Liquidity and Capital Resources, we have issued warrants and may issue common stock under a land agreement. In issuing any warrants and common stock (including common stock underlying the warrants) under the land agreement, we will rely on the exemption from registration provided by Section 4(2) of the Securities Act of 1933, as amended (the Securities Act), for transactions not involving a public offering. Under the land agreement, we issued warrants to purchase 28,576 shares of common stock in 2011 and warrants to purchase 6,983 shares of common stock on January 4, 2012. Please see Item 7. Management s Discussion and Analysis of Financial Condition and Results of Operations Liquidity and Capital Resources Lease Option Arrangements for more information about these warrants, including the conversion prices.

During the second and third quarter of 2011, we contributed \$1.0 million and \$1.1 million (27,640 shares and 38,122 shares), respectively, in our common stock to the University of Texas at Arlington, where we are producing natural gas from a number of wells in the Barnett Shale play. The shares were issued pursuant to an exemption from registration under §4(2) of the Securities Act, for transactions not involving a public offering.

See Item 12. Security Ownership of Certain Beneficial Owners and Management and Related Stockholder Matters for information regarding shares of common stock authorized for issuance under our equity compensation plans.

Item 6. Selected Financial Data

Our financial information set forth below for each of the five years in the period ended December 31, 2011, has been derived from our audited consolidated financial statements. This information should be read in conjunction with Item 7. Management s Discussion and Analysis of Financial Condition and Results of Operations and our consolidated financial statements and related notes included in Item 8. Financial Statements and Supplementary Data

	Year Ended December 31,				
	2011	2010	2009	2008	2007
	(In thousands, except per share data)				
Statements of Operations Data:					
Oil and gas revenues	$ 202,167	$ 138,123	$ 112,699	$ 209,829	$ 125,789
Costs and expenses:					
Oil and gas operating expenses	37,636	31,014	30,321	37,607	24,662
Impairment of oil and gas properties		2,731	338,914	178,470	
Depreciation, depletion and amortization	84,606	47,030	52,005	58,311	41,899
General and administrative	41,781	35,906	30,136	23,425	18,912
Accretion expense related to asset retirement obligations	311	216	308	154	374
Total costs and expenses	164,334	116,897	451,684	297,967	85,847
Operating income (loss)	37,833	21,226	(338,985)	(88,138)	39,942
Gain (loss) on derivative instruments, net	46,991	47,782	41,465	37,499	(1,366)
Loss on extinguishment of debt	(897)	(31,023)		(5,689)	
(Impairment) recovery of investment in Pinnacle		165	(2,091)		
Interest expense, net of amounts capitalized	(29,434)	(22,518)	(18,590)	(9,730)	(14,685)
Other income, net	356	47	49	286	821
Income (loss) before income taxes	54,849	15,679	(318,152)	(65,772)	24,712
Income tax (expense) benefit	(18,220)	(5,729)	113,307	20,725	(9,243)
Net income (loss)	$ 36,629	$ 9,950	$ (204,845)	$ (45,047)	$ 15,469
Basic net income (loss) per common share	$ 0.94	$ 0.29	$ (6.61)	$ (1.49)	$ 0.58
Diluted net income (loss) per common share	$ 0.92	$ 0.29	$ (6.61)	$ (1.49)	$ 0.57
Basic weighted average common shares outstanding	39,077	33,861	31,006	30,326	26,641
Diluted weighted average common shares outstanding	39,668	34,305	31,006	30,326	27,120
Statements of Cash Flows Data:					
Net cash provided by operating activities	$ 154,338	$ 94,416	$ 133,372	$ 148,754	$ 95,231
Net cash used in investing activities	(285,998)	(270,296)	(162,453)	(555,345)	(227,724)
Net cash provided by financing activities	155,644	176,171	27,734	403,749	135,111
Other Cash Flows Data:					
Capital expenditures	$ (556,324)	$ (347,808)	$ (182,907)	$ (571,291)	$ (247,003)
Proceeds from (repayments of) debt(1)	168,436	(840)	31,652	279,259	65,742
Proceeds from common stock offerings, net of offering costs		188,534		135,075	71,926
Balance Sheet Data:					
Working capital (deficit)	$ (150,923)	$ (58,672)	$ (47,328)	$ (57,602)	$ (50,053)
Property and equipment, net	1,310,514	983,057	733,700	986,629	646,810
Total assets	1,527,680	1,144,134	863,107	1,071,702	708,663
Total debt, net of debt discount	729,300	558,254	520,336	475,961	254,501
Total shareholders equity	509,855	456,636	247,609	440,085	310,721

(1) Repayments include amounts refinanced.

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

General Overview

In 2011, we recognized oil and gas revenues of $202.2 million, record production of 45.1 Bcfe and a record level of proved oil and gas reserves at December 31, 2011, of 935.6 Bcfe. The key drivers to our success in 2011 included the following:

Drilling program. Our success is largely dependent on the results of our drilling program. For the year ended December 31, 2011, we drilled 125 gross (54.4 net) wells with an apparent success rate of 99% that was comprised of: (a) 30 of 30 gross (23 net) wells in the Eagle Ford Shale, (b) 8 of 8 gross (4.7 net) wells in the Niobrara, (c) 33 of 34 gross (10.5 net) wells in the Marcellus Shale, (d) 48 of 48 gross (15.3 net) wells in the Barnett Shale, and (e) 5 of 5 gross (.5 net) wells in other project areas in the U.S. At December 31, 2011, 67 of these gross (24.9 net) wells were awaiting completion or pipeline connections.

Production and reserve growth. Our production for the year ended December 31, 2011 was a record 45.1 Bcfe, or 123.4 MMcfe/d, and reflects an increase of 22% from 2010 production of 36.8 Bcfe. The increase in production was primarily due to increased production from new wells, partially offset by normal production decline. As a result of our drilling program discussed above, our proved oil and gas reserves increased 11% to 935.6 Bcfe at December 31, 2011, as compared to 840.7 Bcfe at December 31, 2010 and replacing 311% of 2011 s record production.

Commodity prices. Our average gas price during 2011 was $2.98 per Mcf, $0.35 per Mcf less than the 2010 price of $3.33. Our average oil price in 2011 was $94.16 per Bbl, or $15.52 greater than the price of $78.64 in 2010. Commodity prices are affected by changes in market demand, overall economic activity, weather, pipeline capacity constraints, inventory storage levels, basis differentials and other factors. Our financial results are largely dependent on commodity prices, which are beyond our control and have been and are expected to remain volatile.

Financial flexibility. During 2011, we took steps to continue to strengthen our financial flexibility and to provide funding to accelerate the development of our crude oil and liquids-rich plays in the Eagle Ford Shale and the Niobrara. In November 2011, we completed a private placement of an additional $200.0 million aggregate principal amount of our 8.625% Senior Notes due 2018 (Senior Notes) at a price to the public equal of 98.501% of the principal amount. The net proceeds of approximately $194.5 million (after deducting initial purchasers discounts and our expenses) were used to repay a substantial portion of the borrowings outstanding under our revolving credit facility.

Outlook for 2012

While the market for natural gas remains challenging due to low spot and future prices, we are insulated from a portion of their effect by our hedging of 18,943,000 MMbtus of natural gas for 2012. We are rapidly growing our oil production, part of the effect of which will serve to further reduce our exposure to the weak natural gas market. The current market and outlook for oil and natural gas liquids sales is much more attractive and we are aggressively locking in these prices by increasing our hedge positions as our oil production grows. At December 31, 2011, we had hedges in place for 1,024,800 bbls of oil for 2012. Production growth and commodity prices that permit us to drill, develop and produce at a profit are key to our future success, and we believe the following measures will continue to have a positive impact on our results in 2012:

Control capital costs and maintain financial flexibility. Our Board of Directors has approved a U.S. capital expenditure plan for 2012 of $465.0 million, and we are striving to maintain our financial flexibility and a positive production growth profile. A weakening in commodity prices may cause us to reduce our U.S. capital expenditure plan for 2012.

2012 capital expenditure plan. In 2012, we plan to focus on the drilling and development of our key oil and gas plays. Our 2012 U.S. capital expenditure plan has been set at $465.0 million, which includes $320.0 million in the Eagle Ford Shale, $62.0 million in the Marcellus Shale, $43.0 million for the Niobrara, $15.0 million for the Barnett Shale, and $25.0 million for other areas, all net of carry. Capital expenditures for the Huntington Field development project in the U.K. North Sea are $35.0 million, all of which is expected to be funded by our Huntington Facility. Our capital expenditures could vary from our current plan depending upon various factors, including the availability and cost of drilling rigs, land and industry partner issues, our available cash flow and financing, success of drilling programs, weather delays, commodity prices, market conditions and other factors.

Results of Operations

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

Revenues from oil and gas production for 2011 increased 46% to $202.2 million from $138.1 million in 2010. Production volumes for oil and gas in 2011 increased 22% to 45.1 Bcfe from 36.8 Bcfe in 2010. The increase in production for the year ended December 31, 2011 as compared to the year ended December 31, 2010 was primarily due to increased production from new wells, partially offset by normal production decline. Average oil prices increased 20% to $94.16 per barrel from $78.64 per barrel in 2010. Average natural gas prices decreased 11% to $2.98 per Mcf in 2011 from $3.33 per Mcf in 2010. Average natural gas liquids prices increased 31% to $8.40 per Mcf in 2011 from $6.43 per Mcf in 2010.

The following table summarizes production volumes, average sales prices and oil and gas revenues for the years ended December 31, 2011 and 2010:

	December 31,		2011 Period Compared to 2010 Period	
	2011	2010	Increase (Decrease)	% Increase (Decrease)
Production volumes -				
Oil and condensate (Mbbls)	802	176	626	356%
Natural gas (MMcf)	38,991	34,092	4,899	14%
NGLs (MMcf)	1,257	1,659	(402)	-24%
Average sales prices -				
Oil and condensate (per Bbl)	$ 94.16	$ 78.64	$ 15.52	20%
Natural gas (per Mcf)	2.98	3.33	(0.35)	-11%
NGLs (per Mcf)	8.40	6.43	1.97	31%
Oil and gas revenues (In thousands)				
Oil and condensate	$ 75,502	$ 13,859	$ 61,643	445%
Natural gas	116,103	113,597	2,506	2%
NGLs	10,562	10,667	(105)	-1%
Total	$ 202,167	$ 138,123	$ 64,044	46%

Lease operating expenses for 2011 increased 20% to $28.3 million (or $0.63 per Mcfe) from $23.7 million (or $0.65 per Mcfe) in 2010. Lease operating expenses increased due to increased production. We continue to experience a decrease in the operating cost per Mcfe of our Barnett Shale production which was partially offset by increased operating cost per Mcfe associated with oil production.

Production taxes increased from $3.6 million in 2010 to $5.7 million in 2011 as a result of higher prices and increased production in 2011. The increase in production taxes is due to increased oil and gas production. Production taxes as a percentage of revenues increased from 2.6% to 2.8% due to increased oil production, which has a higher effective production tax rate as compared to natural gas production.

Ad valorem taxes decreased to $3.6 million ($0.08 per Mcfe) in 2011 from $3.7 million ($0.10 per Mcfe) in 2010 due to the sale of substantially all of our non-core area Barnett Shale properties in May 2011, partially offset by new oil and gas wells drilled in 2010.

Depreciation, depletion and amortization (DD&A) expense for 2011 increased to $84.6 million ($1.88 per Mcfe or $11.28 per BOE) from $47.0 million ($1.28 per Mcfe or $7.68 per BOE) in 2010. The increases in DD&A and the related per Mcfe/BOE amounts were primarily due to the increase in crude oil reserves in the Eagle Ford that were added in 2011 which have a higher finding cost per equivalent unit than our natural gas reserves.

In June 2010, we concluded that it was uneconomical to pursue development on the license covering the Monterey field in the U.K. North Sea and terminated further development efforts resulting in a full-cost ceiling test impairment of $2.7 million ($1.7 million net of income taxes) for the year ended December 31, 2010 with respect to the U.K. cost center.

General and administration (G&A) expense for 2011 increased to $41.8 million from $35.9 million in 2010. The increase was due primarily to (a) increased compensation costs related to an increase in personnel in 2011 as compared to 2010, (b) the expense associated with contributions to the University of Texas at Arlington (UTA), a university located within the area of our operations in the Barnett Shale, (c) increased office costs related to relocating our corporate headquarters in the fourth quarter of 2011 partially offset by (d) decreased stock-based compensation expense driven by a significant decrease in the fair value of CSARs due to a decrease in stock price during the second half of 2011, partially offset by higher stock-based compensation expense due to a higher number of stock-based compensation awards outstanding during 2011.

The net gain on derivatives was $47.0 million for the year ended December 31, 2011, comprised of (i) $11.5 million of unrealized gains on derivatives and (ii) $35.5 million of realized gains on derivatives. The net gain on derivatives was $47.8 million for the year ended December 31, 2010, comprised of (i) $14.6 million of unrealized gains on derivatives and (ii) $33.2 million of realized gains on derivatives.

In January 2011, in connection with our entrance into the Revolving Credit Facility, we terminated our Prior Credit Facility. As a result, we recognized a non-cash, pre-tax loss on extinguishment of debt of $0.9 million representing the deferred financing costs attributable to the commitments of two banks in the Prior Credit Facility who did not participate in the Revolving Credit Facility. In November 2010, we completed a tender offer for $300.0 million aggregate principal amount outstanding of the Convertible Senior Notes for an aggregate consideration of approximately $306.3 million, including accrued and unpaid interest on the Convertible Senior Notes. We recognized a $31.0 million pre-tax loss on extinguishment of debt as a result of the purchase of the Convertible Senior Notes in the tender offer, substantially all of which was non-cash representing the associated unamortized discount and deferred financing costs.

Interest expense and capitalized interest in 2011 were $52.8 million and $23.4 million, respectively, as compared to $43.3 million and $20.7 million in 2010, respectively. The increase was primarily due to interest on the $400.0 million aggregate principal amount of 8.625% Senior Notes issued in the fourth quarter of 2010 and the $200.0 million aggregate principal amount of the Senior Notes issued in the fourth quarter of 2011 partially offset by decreased interest attributable to the $300.0 million aggregate principal amount of our 4.375% Convertible Senior Notes purchased in the tender offer during the fourth quarter of 2010. This increase was partially offset by increased capitalized interest due to higher levels of unproved properties during 2011.

Our effective income tax rate was 33.2% for 2011 and 36.5% for 2010. The decrease in the effective income tax rate is primarily due to prior period adjustments related to our state and U.K. income tax provisions recorded during the fourth quarter of 2011 and the income tax benefit of a capital loss associated with our investment in Pinnacle Gas Resources, Inc., which was sold in the first quarter of 2011 for which no income tax benefit was recognized in prior years.

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

Revenues from oil and gas production for 2010 increased 23% to $138.1 million from $112.7 million in 2009. Production volumes for oil and gas in 2010 increased 11% to 36.8 Bcfe from 33.0 Bcfe in 2009. The increase in production for the year ended December 31, 2010 as compared to the year ended December 31, 2009 was primarily due to increased production from new Barnett Shale wells partially offset by normal production decline and the shut in of a high volume gas well in the Gulf Coast area for a workover and sidetrack during the third quarter of 2010. Average natural gas and NGL prices increased to $3.48 per Mcf in 2010 from $3.20 per Mcf in 2009. Average oil prices increased 34% to $78.64 per barrel from $58.85 per barrel in 2009.

The following table summarizes production volumes, average sales prices and oil and gas revenues for the years ended December 31, 2010 and 2009:

	December 31,		2010 Period Compared to 2009 Period	
	2010	2009	Increase (Decrease)	% Increase (Decrease)
Production volumes -				
Oil and condensate (Mbbls)	176	174	2	1%
Natural gas and NGLs (MMcf)[1]	35,751	32,002	3,749	12%
Average sales prices -				
Oil and condensate (per Bbl)	$ 78.64	$ 58.85	$ 19.79	34%
Natural gas and NGLs (per Mcf)	3.48	3.20	0.28	9%
Oil and gas revenues (In thousands)				
Oil and condensate	$ 13,859	$ 10,217	$ 3,642	36%
Natural gas and NGLs	124,264	102,482	21,782	21%
Total	$ 138,123	$ 112,699	$ 25,424	23%

(1) Includes 1,659.2 and 1,975.2 MMcfe of natural gas liquids in 2010 and 2009, respectively.

Lease operating expenses for 2010 decreased 6% to $23.7 million (or $0.65 per Mcfe) from $25.1 million (or $0.76 per Mcfe) in 2009. A decrease in service costs and lower transportation costs were partially offset by increased operating expenses associated with increased production. The decrease in service costs was driven primarily by a decrease in operating expenses related to a pipeline and gathering system that was sold during the fourth quarter of 2009 and the increase in production from our Tarrant county, Barnett Shale area, which has comparatively less associated salt water production that must be disposed of than production from other areas. The decrease in transportation costs was primarily due to our decision to begin selling our natural gas production at the wellhead in July 2009.

Production taxes increased from $0.1 million in 2009 to $3.6 million in 2010 as a result of a severance tax refund of $2.0 million in 2009 and higher prices and increased production in 2010.

Ad valorem taxes decreased 26% to $3.7 million in 2010 from $5.0 million in 2009 primarily due to lower property valuations in 2010.

DD&A expense for 2010 decreased 10% to $47.0 million (or $1.28 per Mcfe) from $52.0 million (or $1.57 per Mcfe) in 2009. This decrease in DD&A was primarily due to impairment charges in the first and fourth quarters of 2009 that reduced the depletable base of the full cost pool, partially offset by increased production and increased future development costs attributable to crude oil and natural gas liquids reserves added during the fourth quarter of 2010, which have a higher future development cost per equivalent unit than our proved gas reserves. We expect a higher depletion rate in 2011 as we continue to pursue our new growth strategy in crude oil and liquids-rich plays due to the higher future development costs per equivalent unit associated with such plays as compared to our gas reserves.

In June 2010, we concluded that it was uneconomical to pursue development on the license covering the Monterey field in the U.K. North Sea and terminated further development efforts resulting in a full-cost ceiling test impairment of $2.7 million ($1.7 million net of income taxes) for the year ended December 31, 2010 with respect to the U.K. cost center. The significant decline in oil and natural gas prices since mid-2008 and the continued depressed price of natural gas in 2009, caused the discounted present value of future net cash flows from our proved oil and gas reserves to fall below our net book basis in the proved oil and gas properties at March 31, 2009 and December 31, 2009. This resulted in non-cash, full cost ceiling test write-downs of $216.4 million ($140.6 million net of income taxes) and $122.5 million ($78.1 million net of income taxes) at March 31, 2009 and December 31, 2009, respectively.

G&A expense for 2010 increased 19% to $35.9 million from $30.1 million in 2009. The increase was due primarily to (a) increased stock-based compensation largely attributable to additional SARs granted in July 2010 and existing SARs that increased in fair value in the second half of 2010, and (b) increased compensation costs largely due to an increase in the number of employees in 2010 partially offset by (c) the expense associated with a pledge of $1.0 million made to UTA, in the third quarter of 2009 for which there is no corresponding expense in the 2010 period.

The net gain on derivatives was $47.8 million for the year ended December 31, 2010, comprised of (i) $14.6 million of unrealized gains on derivatives and (ii) $33.2 million of realized gains on derivatives. The net gain on derivatives was $41.5 million for the year ended December 31, 2009, comprised of (i) $33.3 million of unrealized losses on derivatives and (ii) $74.9 million of realized gains on derivatives.

In November 2010, we completed a tender offer for $300.0 million aggregate principal amount outstanding of the Convertible Senior Notes for an aggregate consideration of approximately $306.3 million, including accrued and unpaid interest on the Convertible Senior Notes. We recognized a $31.0 million pre-tax loss on extinguishment of debt as a result of the purchase of the Convertible Senior Notes in the tender offer, substantially all of which was non-cash representing the associated unamortized discount and deferred financing costs.

Interest expense and capitalized interest in 2010 were $43.3 million and $20.7 million, respectively, as compared to $38.3 million and $19.7 million in 2009, respectively. The net increase was primarily due to interest on the $400.0 million aggregate principal amount of 8.625% Senior Notes which were issued in the fourth quarter of 2010, increased amortization of deferred financing costs related to our prior revolving credit facility, partially offset by decreased interest attributable to the $300.0 million aggregate principal amount of the 4.375% Convertible Senior Notes repurchased in the tender offer during the fourth quarter of 2010 and higher capitalized interest due to higher levels of unproved properties during 2010.

Our overall effective tax rate was 36.5% for 2010 and 35.6% for 2009. The increase in the effective tax rate was primarily due to a true-up of prior year estimates of state income taxes during 2010 and state income taxes on the cash distributions received on our B Unit investment in ACP II during the third and fourth quarters of 2010.

Liquidity and Capital Resources

2012 Capital Expenditure Plan and Funding Strategy. For 2012, our Board has approved a U.S. capital expenditure plan of $465.0 million which includes approximately $320.0 million for the Eagle Ford Shale, $62.0 million for the Marcellus Shale, $43.0 million for the Niobrara, $15.0 for the Barnett Shale, and $25.0 million for other areas, all net of carry. Capital expenditures for the Huntington Field development project in the U.K. North Sea are $35.0 million, all of which is expected to be funded by our Huntington Facility. We intend to finance the remainder of our 2012 U.S. capital expenditure plan primarily from the sources described below under Sources and Uses of Cash. Our capital program could vary depending upon various factors, including the availability and cost of drilling rigs, land and industry partner issues, our available cash flow and financing, success of drilling programs, weather delays, commodity prices, market conditions, the acquisitions of leases with drilling commitments and other factors.

Sources and Uses of Cash. Our primary use of cash is capital expenditures related to our drilling and development programs and, to a lesser extent, our lease and seismic data acquisition programs. The actual amount of investment could vary depending upon various factors, including the availability and cost of drilling rigs, land and industry partner issues, our available cash flow, success of drilling programs, weather delays, commodity prices, market conditions, the acquisition of leases with drilling commitments and other factors. For the year ended December 31, 2011, capital expenditures, net of proceeds from asset sales, exceeded our net cash provided by operations. During 2011, we funded our capital expenditures with cash provided by operations, proceeds from the sale of assets, payments or carried interest relating to our joint ventures with Reliance and GAIL, offering of $200.0 million in aggregate principal of Senior Notes, and borrowings under our revolving credit facility, the Huntington Facility and our prior credit facility that was in place until January 27, 2011. Potential sources of future liquidity include the following:

Cash on hand and cash generated by operations. Cash flows from operations are highly dependent on commodity prices and market conditions for oilfield services. We hedge a portion of our production to mitigate the risk of a decline in oil and gas prices.

Borrowings under our revolving credit facility and Huntington Facility. In January 2011, we closed a new $750.0 million senior secured revolving credit facility with a current borrowing base of $340.0 million. This facility matures in January 2016 and expanded our ability to enter into limited recourse financing arrangements such as our Huntington Facility. At February 27, 2012, $113.0 million and $24.6 million of borrowings were outstanding under our revolving credit facility and Huntington Facility, respectively. The next borrowing base redetermination for our revolving credit facility is currently scheduled for May 1, 2012. We have also issued $0.4 million of letters of credit outstanding under the revolving credit facility, which reduce the amounts available under our revolving credit facility. The amount we are able to borrow with respect to the borrowing base is subject to compliance with the financial covenants and other provisions of the credit agreement governing our revolving credit facility.

Borrowings under project financing arrangements in certain limited circumstances. As described above, we plan to fund a substantial portion of our costs relating to the Huntington Field development project from our Huntington Facility.

Asset sales. In the second quarter of 2011, we sold certain non-core area Barnett Shale properties for net proceeds of approximately $98.0 million, net of purchase price adjustments. In the third quarter of 2011, we completed the sale of 20% of our interests in oil and gas properties in parts of the Eagle Ford Shale to GAIL effective September 1, 2011 for net proceeds of approximately $63.7 million in cash. As part of the consideration for the purchase, GAIL has committed to pay a development carry of 50% of certain of our future development costs up to approximately $31.3 million. We used the net proceeds from these sales to repay borrowings under our revolving credit facility and used the additional capacity under our revolving credit facility to fund, in part, our 2011 capital expenditure plan and for general corporate purposes. In order to fund our U.S. capital expenditure plan, we may consider the sale of certain properties or assets, including our interest in the Huntington Field development project in the U.K. North Sea, that are not part of our core business, or are no longer deemed essential to our future growth, and provided that we are able to sell such assets on terms that are acceptable to us.

Securities offerings. In November 2011, we sold an additional $200.0 million in aggregate principal of Senior Notes in a private placement, which were guaranteed by substantially all of our wholly owned domestic subsidiaries (other than Carrizo (Utica) LLC). We used the net proceeds of approximately $194.5 million after deducting initial purchasers discounts and our expenses, to repay a substantial portion of the borrowings then-outstanding under our revolving credit facility. As situations or conditions arise, we may need to issue debt, equity or other instruments to supplement our cash flows. However, we may not be able to obtain such financing on terms that are acceptable to us, or at all.

Lease option agreements and land banking arrangements, such as those we have entered into in the Barnett Shale and other plays. Please read Lease Option Arrangements .

Joint ventures with third parties through which such third parties fund a portion of our exploration activities to earn an interest in our exploration acreage and/or purchase a portion of interests, such as our joint ventures with GAIL in the Eagle Ford Shale, Avista and Reliance in the Marcellus Shale, Avista in the Utica Shale and Sumitomo in the Barnett Shale.

We may consider sale/leaseback transactions of certain capital assets, such as our remaining pipelines and compressors, which are not part of our core oil and gas exploration and production business.

Our primary use of cash is capital expenditures related to our drilling and development programs and, to a lesser extent, our lease and seismic data acquisition programs. As mentioned above, our 2012 U.S. capital expenditure plan has been set at $465.0 million with the $35.0 million of capital expenditures for the Huntington Field development project in the U.K. North Sea, expected to be funded by our Huntington Facility. The actual amount of investment could vary depending upon various factors, including the availability and cost of drilling rigs, land and industry partner issues, our available cash flow, success of drilling programs, weather delays, commodity prices, market conditions and other factors.

Overview of Cash Flow Activities. Cash flows provided by operating activities were $154.3 million, $94.4 million and $133.4 million for the years ended December 31, 2011, 2010, and 2009, respectively. The increase was primarily due to increased production, particularly higher crude oil and condensate production in the Eagle Ford Shale and increased oil prices, partially offset by lower gas prices in 2011 as compared to 2010. Cash flows decreased in 2010 from 2009 due to lower realized hedge gains in 2010 as compared to 2009 partially offset by increased production and oil and gas prices.

Cash flows used in investing activities were $286.0 million for the year ended December 31, 2011 and related primarily to capital expenditures, partially offset proceeds from the sale of our non-core area Barnett Shale properties to KKR, proceeds from the sale of an interest in certain of our Eagle Ford Shale properties to GAIL and cash distributions on our B Unit investment in ACP II of $3.3 million. Cash flows used in investing activities were $270.3 million for the year ended December 31, 2010 and related primarily to capital expenditures, partially offset by proceeds from the sale of an interest in our Pennsylvania properties to Reliance and cash distributions on our B Unit investment in ACP II. The increase in investing activities in 2010 from 2009 was largely due to higher expenditures for oil and gas properties due to our growth strategy into crude oil and liquids-rich plays in the Eagle Ford Shale and the Niobrara.

Net cash provided by financing activities for the year ended December 31, 2011 was $155.6 million and related primarily to net proceeds of $194.5 million from the issuance of an additional $200.0 million aggregate principal amount of Senior Notes in November 2011. The net proceeds were used to repay a substantial portion of the borrowings outstanding under the Senior Secured Revolving

Credit Facility. Net cash provided by financing activities for the year ended December 31, 2010 was $176.2 million and related primarily to net proceeds of $188.5 million from the issuances of common stock in April and December of 2010. Proceeds from the November 2010 issuance of $400.0 million aggregate principal amount of Senior Notes were offset by the purchase of $300.0 million of Convertible Senior Notes by tender offer and repayment of amounts outstanding under our prior credit facility. Net cash provided by financing activities for the year ended December 31, 2009 was $27.7 million and related primarily to net borrowings of $32.4 million under our prior credit facility.

Liquidity/Cash Flow Outlook

Economic downturns may adversely affect our ability to access capital markets in the future. We currently believe that cash provided by operating activities, the sale of non-core assets and borrowings under our revolving credit facility and the Huntington Facility will be sufficient to fund our immediate cash flow requirements. Cash provided by operating activities is primarily driven by production and commodity prices. While we have steadily increased production over the last few years, spot and futures prices of natural gas continue to remain depressed. To manage our exposure to commodity price risk and to provide a level of certainty in the cash flows that will support our capital expenditures program, we hedge a portion of our production and, as of February 27, 2012, we had hedged approximately 15,583,000 MMBtu (51,000 MMcf per day for the remainder of 2012) of our estimated March through December 2012 natural gas production at a weighted average floor or swap price of $5.37 per MMBtu relative to WAHA and Houston Ship Channel prices. Additionally, we had hedged approximately 1,468,800 Bbls (4,800 Bbls per day for the remainder of 2012) of our estimated March through December 2012 crude oil production at a weighted average floor or swap price of $86.15 per Bbl relative to NYMEX prices. We have $113.0 million and $24.6 million outstanding under our revolving credit facility and Huntington Facility, respectively, as of February 27, 2012. Our borrowing base under our revolving credit facility is currently $340.0 million. We have issued $0.4 million of letters of credit, which reduce the amounts available under our revolving credit facility. Additionally, as described under Sources and Uses of Cash above, the amount we are able to borrow with respect to the borrowing base is subject to compliance with the financial covenants and other provisions of the credit agreement governing the revolving credit facility. We are scheduled for a borrowing base redetermination as of May 1, 2012, at which time our borrowing base may change. The borrowing base is affected by our banks assumptions with respect to future oil and gas prices. Our borrowing base may decrease if our banks reduce their expectations with respect to future oil and gas prices from those assumptions used to determine our existing borrowing base.

If cash provided by operating activities, funds available under our revolving credit facility and the Huntington Facility and the other sources of cash described under Sources and Uses of Cash are insufficient to fund our 2012 capital expenditure plan, we may need to reduce our capital expenditure plan or seek other financing alternatives to fund it. We may not be able to obtain financing needed in the future on terms that would be acceptable to us, or at all. If we cannot obtain adequate financing, we may be required to limit or defer our planned 2012 capital expenditure plan, thereby adversely affecting the recoverability and ultimate value of our oil and gas properties.

Contractual Obligations

The following table sets forth estimates of our contractual obligations as of December 31, 2011:

	Total	2012	2013	2014	2015	2016	2017 and Beyond
Long-term debt (1)	$ 738,563	$	$ 73,750	$ 17,813	$	$ 47,000	$ 600,000
Interest on long-term debt (2)	375,310	57,206	55,593	53,979	53,176	51,856	103,500
Operating leases	12,886	64	1,179	1,370	1,370	1,370	7,533
Drilling contracts	132,979	54,994	41,158	30,509	6,318		
Pipeline volume commitments	65,916	11,418	15,579	16,343	14,553	8,023	
Asset retirement obligations	12,168	925	181	298	75	114	10,575
Seismic obligations	2,959	2,959					
Other	1,355	1,355					
Total Contractual Obligations	$ 1,342,136	$ 128,921	$ 187,440	$ 120,312	$ 75,492	$ 108,363	$ 721,608

(1) Noteholders may require us to repurchase the Convertible Senior Notes in June 2013, June 2018, or June 2023. The table assumes that the holders of the Convertible Senior Notes exercise this right on the first available date (in June 2013).

(2) Interest on long-term debt is based on the 8.625% rate on the Senior Notes, the 4.375% rate on the Convertible Senior Notes, the December 31, 2011 average interest rate of 3.03% for amounts outstanding under our revolving credit facility and the December 31, 2011 average interest rate of 4.51% for amounts outstanding under the Huntington Facility.

Off Balance Sheet Arrangements

We currently do not have any off balance sheet arrangements.

Financing Arrangements

Senior Notes

As of December 31, 2011 the Company had $600.0 million aggregate principal amount of 8.625% Senior Notes due 2018 (Senior Notes) issued and outstanding. The Senior Notes are guaranteed by certain of the Company s domestic subsidiaries: Bandelier Pipeline Holding, LLC; Carrizo (Eagle Ford) LLC; Carrizo (Marcellus) LLC; Carrizo (Marcellus) WV LLC, Carrizo Marcellus Holding, Inc.; Carrizo (Niobrara) LLC; CLLR, Inc.; Hondo Pipeline, Inc.; and Mescalero Pipeline, LLC.

The Senior Notes mature on October 15, 2018 with interest payable semi-annually. At any time prior to October 15, 2013, the Company may, subject to certain conditions, redeem up to 35% of the aggregate principal amount of Senior Notes at a redemption price of 108.625% of the principal amount, plus accrued and unpaid interest, using the net cash proceeds of one or more equity offerings by the Company. Prior to October 15, 2014, the Company may redeem all or part of the Senior Notes at 100% of the principal amount thereof, plus accrued and unpaid interest, if any, and a make whole premium. On and after October 15, 2014, the Company may redeem all or a part of the Senior Notes, at redemption prices decreasing from 104.313% of the principal amount to 100% of the principal amount on October 15, 2017, plus accrued and unpaid interest. If a Change of Control (as defined in the indenture governing the Senior Notes) occurs, the Company may be required by holders to repurchase Senior Notes for cash at a price equal to 101% of the aggregate principal amount, plus any accrued but unpaid interest.

The indenture governing the Senior Notes contains covenants that, among other things, limit the Company s ability and the ability of its restricted subsidiaries to: pay distributions on, purchase or redeem the Company s common stock or other capital stock or redeem the Company s subordinated debt; make investments; incur or guarantee additional indebtedness or issue certain types of equity securities; create certain liens; sell assets; consolidate, merge or transfer all or substantially all of the Company s assets; enter into agreements that restrict distributions or other payments from the Company s restricted subsidiaries to the Company; engage in transactions with affiliates; and create unrestricted subsidiaries.

The Senior Notes are subject to customary events of default, including those relating to failures to comply with the terms of the indenture governing the Senior Notes, certain failures to file reports with the Securities and Exchange Commission (SEC) and certain cross defaults of other indebtedness and mortgages and certain failures to pay final judgments.

Convertible Senior Notes

In May 2008, the Company issued $373.8 million aggregate principal amount of 4.375% convertible senior notes due 2028 (the Convertible Senior Notes). Interest is payable on June 1 and December 1 each year. The notes are convertible, using a net share settlement process, into a combination of cash and Company common stock that entitles holders of the Convertible Senior Notes to receive cash up to the principal amount ($1,000 per note) and common stock in respect of the remainder, if any, of the Company s conversion obligation in excess of such principal amount.

In November 2010, the Company completed a tender offer for $300.0 million aggregate principal amount of the Convertible Senior Notes for an aggregate consideration of approximately $306.3 million, including accrued and unpaid interest on the Convertible Senior Notes. Each holder received $1,000 for each $1,000 principal amount of Convertible Senior Notes purchased in the tender offer, plus accrued and unpaid interest. The Company recognized a $31.0 million pre-tax loss on extinguishment of debt as a result of the purchase of the Convertible Senior Notes in the tender offer, substantially all of which was non-cash representing the associated unamortized discount and deferred financing costs. As of December 31, 2011, $73.8 million aggregate principal amount of Convertible Senior Notes was outstanding.

The notes are convertible into the Company s common stock at a ratio of 9.9936 shares per $1,000 principal amount of notes, equivalent to a conversion price of approximately $100.06. This conversion rate is subject to adjustment upon certain corporate events. In addition, if certain fundamental changes occur on or before June 1, 2013, the Company will in some cases increase the conversion rate for a holder electing to convert notes in connection with such fundamental change; provided, that in no event will the total number of shares issuable upon conversion of a note exceed 14.7406 per $1,000 principal amount of notes (subject to adjustment in the same manner as the conversion rate).

Holders may convert the notes only under the following conditions: (a) during any calendar quarter if the last reported sale price of the Company s common stock exceeds 130 percent of the conversion price for at least 20 trading days in a period of 30 consecutive trading days ending on the last trading day of the immediately preceding calendar quarter, (b) during the five business days after any five consecutive trading day period in which the trading price per $1,000 principal amount of the notes is equal to or less than 97% of the conversion value of such notes, (c) during specified periods if specified distributions to holders of the Company s common stock are made or specified corporate transactions occur, (d) prior to the close of business on the business day preceding the redemption date if the notes are called for redemption or (e) on or after March 31, 2028 and prior to the close of business on the business day prior to the maturity date of June 1, 2028.

The holders of the Convertible Senior Notes may require the Company to repurchase the notes on June 1, 2013, 2018 and 2023, or upon a fundamental corporate change at a repurchase price in cash equal to 100 percent of the principal amount of the notes to be repurchased plus accrued and unpaid interest, if any. The Company may redeem notes at any time on or after June 1, 2013 at a redemption price equal to 100 percent of the principal amount of the notes to be redeemed plus accrued and unpaid interest, if any.

The Convertible Senior Notes are subject to customary non-financial covenants and events of default, including a cross default under our revolving credit facility, the occurrence and continuation of which could result in the acceleration of amounts due under the Convertible Senior Notes. The Convertible Senior Notes are unsecured obligations of the Company and rank equal to the Senior Notes and all future senior unsecured debt of the Company but rank second in priority to our revolving credit facility. The Convertible Senior Notes are guaranteed by the same subsidiaries that guarantee the Senior Notes as described above.

We valued the Convertible Senior Notes at May 21, 2008, as $309.6 million of debt and $64.2 million of equity representing the fair value of the conversion premium. The resulting debt discount is being amortized to interest expense through June 1, 2013, the first date on which the holders may require us to repurchase the Convertible Senior Notes, resulting in an effective interest rate of approximately 8% for the Convertible Senior Notes. Approximately $27.1 million of the unamortized debt discount associated with the Convertible Senior Notes purchased in the tender offer discussed above, was recognized as a component of the loss on the extinguishment of debt. Amortization of the debt discount amounted to $2.6 million, $11.6 million and $12.1 million for the years ended December 31, 2011, 2010 and 2009 respectively.

Senior Secured Revolving Credit Facility

In January 2011, we entered into a new senior secured revolving credit facility. The new revolving credit facility replaced our prior credit facility. The new revolving credit facility permits us to borrow up to the lesser of (i) the borrowing base (as defined in the credit agreement governing our new revolving credit facility) and (ii) $750.0 million. The revolving credit facility matures on January 27, 2016. It is secured by substantially all of our assets (excluding our Carrizo UK assets described below under Huntington Field Development Project Credit Facility and our Utica Shale assets) and is guaranteed by certain of our subsidiaries: Bandelier Pipeline Holding, LLC, Carrizo (Eagle Ford) LLC, Carrizo Marcellus Holding Inc., Carrizo (Marcellus) LLC, Carrizo (Marcellus) WV LLC, Carrizo (Niobrara) LLC, CLLR, Inc., Hondo Pipeline, Inc. and Mescalero Pipeline, LLC. Any subsidiary of ours that does not currently guarantee our obligations under our revolving credit facility that subsequently becomes a material domestic subsidiary (as defined under our revolving credit facility) will be required to guarantee our obligations under our revolving credit facility.

The current borrowing base under the revolving credit facility is $340.0 million. The borrowing base will be redetermined by the lenders at least semi-annually on each May 1 and November 1, with the next redetermination expected as of May 1, 2012. We and the lenders may each request one unscheduled borrowing base redetermination between each scheduled redetermination. The borrowing base will also be reduced in certain circumstances as a result of certain issuances of senior notes, cancellation of certain hedging positions and as a result of certain asset sales. The amount we are able to borrow with respect to the borrowing base is subject to compliance with the financial covenants and other provisions of the credit agreement governing the revolving credit facility.

If the outstanding principal balance of the revolving loans and the aggregate face amount of all letters of credit under the revolving credit facility exceeds the borrowing base at any time as a result of a redetermination of the borrowing base, we have the option within 30 days to take any of the following actions, either individually or in combination: make a lump sum payment curing the deficiency, deliver reserve engineering reports and mortgages covering additional oil and gas properties sufficient in the lenders opinion to increase the borrowing base and cure the deficiency or begin making equal monthly principal payments that will cure the deficiency within the next six-month period. Upon certain adjustments to the borrowing base, we are required to make a lump sum payment in an amount equal to the amount by which the outstanding principal balance of the revolving loans and the aggregate face amount of all letters of credit under the revolving credit facility exceeds the borrowing base. Otherwise, any unpaid principal will be due at maturity.

The annual interest rate on each base rate borrowing is (a) the greatest of the Agent s Prime Rate, the Federal Funds Effective Rate plus 0.5% and the adjusted LIBO rate for a three-month interest period on such day plus 1.00%, plus (b) a margin between 1.00% and 2.00% (depending on the then-current level of borrowing base usage). The interest rate on each Eurodollar loan will be the adjusted LIBO rate for the applicable interest period plus a margin between 2.00% to 3.00% (depending on the then-current level of borrowing base usage).

We are subject to certain covenants under the terms of the revolving credit facility which include, but are not limited to, the maintenance of the following financial covenants: (i) a Total Debt to EBITDA (each as defined in the credit agreement governing the revolving credit facility) ratio of not more than (a) 4.75 to 1.00 for fiscal quarter ending December 31, 2011 (b) 4.25 to 1.00 for fiscal quarters ending March 31, 2012 and June 30, 2012 and (c) 4.00 to 1.00 for fiscal quarters ending September 30, 2012 and thereafter; (ii) a current ratio of not less than 1.0 to 1.0; (iii) a Senior Debt (as defined in the credit agreement governing our revolving credit facility) to EBITDA ratio of not more than 2.50 to 1.00; and (iv) an EBITDA to Interest Expense (as defined in the credit agreement governing our revolving credit facility) ratio of not less than 2.50 to 1.00. At December 31, 2011, the ratio of Total Debt to EBITDA was 3.99 to 1.00, the Current Ratio was 1.55 to 1.0, the Senior Debt to EBITDA ratio was 0.08 to 1.00 and the EBITDA to Interest Expense ratio was 4.35 to 1.00.

The revolving credit facility also places restrictions on us and certain of our subsidiaries with respect to additional indebtedness, liens, dividends and other payments to shareholders, repurchases or redemptions of our common stock, redemptions of our Senior Notes, investments, acquisitions, mergers, asset dispositions, transactions with affiliates, hedging transactions and other matters.

The revolving credit facility is subject to customary events of default, including a change in control (as defined in the credit agreement governing our revolving credit facility). If an event of default occurs and is continuing, the Majority Lenders (as defined in the credit agreement governing the revolving credit facility) may accelerate amounts due under the revolving credit facility (except for a bankruptcy event of default, in which case such amounts will automatically become due and payable).

At December 31, 2011, we had $47.0 million of borrowings outstanding under the revolving credit facility with a weighted average interest rate of 3.03%. At December 31, 2011, we also had $0.4 million in letters of credit outstanding which reduced the amounts available under the revolving credit facility. Future availability under the $340.0 million borrowing base is subject to the terms and covenants of the revolving credit facility. The revolving credit facility is used to fund ongoing working capital needs and the remainder of our capital expenditure plan only to the extent such amounts exceed the cash flow from operations, proceeds from the sale of oil and gas properties and securities offerings.

Huntington Field Development Project Credit Facility

On January 28, 2011, we and Carrizo UK, as borrower, entered into the Huntington Facility. The Huntington Facility is secured by substantially all of Carrizo UK s assets and is limited recourse to us. The Huntington Facility provides financing for a substantial portion of Carrizo UK s share of costs associated with the Huntington Field development project in the U.K. North Sea. The Huntington Facility provides for a multicurrency credit facility consisting of (i) a term loan facility to be used to fund Carrizo UK s share of project development costs, (ii) a contingent cost overrun term loan facility and (iii) a post-completion revolving credit facility providing for loans and letters of credit to be used to fund certain abandonment and decommissioning costs following project completion.

The total term loan facility commitment is $55.0 million, with availability under the facility subject to a borrowing base, which is currently in excess of the commitment. The total cost overrun facility commitment is $6.5 million, which may be utilized only when funds under the term loan facility have been exhausted and certain other requirements are satisfied. The total post-completion revolving credit facility commitment is $22.5 million. Availability under each of the term loan facility and the cost overrun facility is subject to borrowing bases that are generally based on consolidated cash flow and debt service projections for Carrizo UK attributable to certain proved reserves in the Huntington Field development project. The borrowing bases of the term loan facility and the cost overrun facility will be redetermined by the lenders at least semi-annually on each April 1 and October 1 in connection with the updating and recalculation of revenue and cash flow projections with respect to the Huntington Field development project. If the outstanding principal balance of the term loan facility and cost overrun facility exceeds the aggregate borrowing base for such facility at any time as a result of a redetermination of such facility s borrowing base, Carrizo UK will be obligated to make a payment to cure the deficiency within five business days.

Initial borrowings under the term loan facility and cost overrun facility were conditioned on, among other things, our having made an approximate $22.0 million equity contribution to Carrizo UK, which was completed during the first quarter of 2011. Prior to project completion, the Company may be responsible under the Huntington Facility for making an additional equity contribution to Carrizo UK in the event the term loan borrowing base is reduced to a level at or above the amount of borrowings then outstanding. The Company may also be responsible under the Huntington Facility for making certain additional equity contributions to Carrizo UK in the event of certain specified projected Cost Overruns (as defined in the Huntington Facility). To the extent that the cost overrun facility and any required equity contributions are insufficient, the Company is responsible for funding any Cost Overruns on a 100% basis. If after project completion, the lenders reasonably determine that Carrizo UK is required to incur additional capital expenditures that were not contemplated by the Huntington Field development plan originally approved by the U.K. Department of Energy and Climate Change, the Company responsible for funding such additional expenditures. The Company is responsible for making certain other payments under the Huntington Facility, including funding certain projected working capital shortfalls, providing cash collateral for letters of credit issued under the post-completion revolving credit facility and paying certain costs of the required hedging arrangements described below.

The annual interest rate on each borrowing is (a) LIBOR (EURIBOR for euro-denominated loans) for the applicable interest period, plus (b) a margin of (i) 3.50% until the completion of the Huntington Field development project and 3.0% thereafter for the term loan credit facility and post-completion revolving credit facility or (ii) 4.75% for the cost overrun facility. Borrowings under the term loan and cost overrun facilities are available until the earlier of December 31, 2012 or the achievement of certain project development milestones. The term loan and cost overrun facilities mature on December 31, 2014, subject to acceleration in the event that future projection estimates of remaining reserves in the project area have declined to less than 25% of the level initially projected by Carrizo UK and the lenders. Letters of credit under the post-completion revolving credit facility mature on December 31, 2016. Amounts outstanding under the term loan or cost overrun facility must be repaid according to the following schedule: (i) 45% will be due on December 31, 2012, (ii) 20% will be due on June 30, 2013, (iii) 20% will be due on December 31, 2013, (iv) 10% will be due on June 30, 2014 and (iv) the remaining 5% will be due on the final maturity date of December 31, 2014. We are currently negotiating with the lenders of the Huntington Facility to modify the repayment schedule as we currently expect first production in the fourth quarter of 2012.

The Huntington Facility requires Carrizo UK to enter into certain hedging arrangements in order to hedge a specified portion of the Huntington Field development project s exposure to fluctuating petroleum prices. This obligation was satisfied in February 2011. In addition, Carrizo UK may, but is not required, to hedge its exposure to changes in interest rates or exchange rates, and permits Carrizo UK to enter into additional hedging arrangements. The Huntington Facility places restrictions on Carrizo UK with respect to additional indebtedness, liens, the extension of credit, dividends or other payments to us or our other subsidiaries, investments, acquisitions, mergers, asset dispositions, commodity transactions outside of the mandatory hedging program, transactions with affiliates and other matters.

The Huntington Facility is subject to customary events of default. If an event of default occurs and is continuing, the Majority Lenders (as defined in the Huntington Facility) may accelerate amounts due under the Huntington Facility.

As of December 31, 2011, borrowings outstanding under the Huntington Facility were £11.5 million, with a weighted average interest rate of 4.51% and no letters of credit had been issued. The British Pound denominated borrowings were translated to $17.8 million at December 31, 2011, resulting in an immaterial transaction gain recorded in Other income, net in the consolidated statements of operations.

Securities Offerings in 2011, 2010 and 2009

In November 2011, we issued $200.0 million aggregate principal amount of Senior Notes in a private placement exempt from the registration requirements of the Securities Act. We used the net proceeds of approximately $194.5 million after deducting initial purchasers discounts and our estimated expenses, to repay a substantial portion of the borrowings then outstanding under our revolving credit facility. In February 2012, we completed an exchange offer and issued new notes and guarantees having substantially identical terms, but registered with the SEC, in exchange for all such privately issued Senior Notes. The $200.0 million of Senior Notes issued in November 2011 have substantially identical terms as, and are treated as a single series with, the $400.0 million of Senior Notes described in the following paragraph. Holders of all $600.0 million aggregate principal amount of Senior Notes will vote as one series under the indenture governing the Senior Notes.

In November 2010, we issued $400.0 million aggregate principal amount of Senior Notes in a private placement exempt from the registration requirements of the Securities Act. We used the net proceeds of approximately $387.5 million after deducting initial purchasers discounts and our estimated expenses, to repay initially in full borrowings outstanding under our prior credit facility and held the remaining net proceeds in short-term investments. We subsequently purchased the $300.0 million of Convertible Senior Notes in the tender offer with a combination of cash on hand and borrowings under our prior credit facility. In June 2011, we completed an exchange offer and issued new notes and guarantees having substantially identical terms, but registered with the SEC, in exchange for all such privately issued Senior Notes.

In December 2010, we sold 3.98 million shares of our common stock in an underwritten public offering at a price to the underwriter of $28.90 per share. We used the net proceeds of approximately $114.9 million to repay a portion of the outstanding borrowings under our prior credit facility.

In April 2010, we sold 3.22 million shares of our common stock in an underwritten public offering at a price to the underwriter of $23.00 per share. We used the net proceeds of approximately $73.8 million to repay a portion of the then-outstanding borrowings under our prior credit facility.

Lease Option Arrangements

From time to time, we have entered into lease purchase option arrangements with third parties. In the first half of 2011, we utilized one lease purchase option arrangement described below with an unrelated third party. Strategically, such leasing arrangements have allowed us to temporarily control important acreage positions during periods that we have lacked sufficient capital to directly acquire such oil and gas leases. We may continue to use these arrangements as a strategic alternative in the future.

On November 24, 2009, we entered into a Land Agreement (the Land Agreement) with an unrelated third party and its affiliate. The Land Agreement expired by its terms on May 31, 2011. Under this arrangement, we were permitted to acquire up to $20.0 million of oil, gas and mineral interests/leases in certain specified areas in the Barnett Shale from the third party. In consideration of our receipt of an option to purchase the leases acquired by the third party (as described below), each time the third party purchased a lease group under the Land Agreement, if any, we would issue to the third party s affiliate warrants to purchase a number of shares of our common stock equal to the quotient of (rounded up to the nearest whole number) (1) 20% of the purchase price of such lease group divided by (2) $13.00, with an exercise price of $22.09 and an expiration date of August 21, 2017. In addition, under certain circumstances where we reach surface casing point on an initial well in one of the areas covered by the Land Agreement but have not achieved a specified lease up threshold for acreage in such area, we will issue additional warrants to the third party s affiliate, on the same terms, to purchase a number of shares of common stock equal to the quotient (rounded up to the nearest whole number) of (1) 20% of the product of (A) the number of acres below the specified lease up threshold multiplied by (B) $5,000, divided by (2) $13.00. The warrants are subject to antidilution adjustments and may be exercised on a cashless basis.

We had the option to purchase the lease groups acquired by the third party within 180 days after the third party s acquisition at a cost equal to 110% of the original purchase price. We paid the purchase price for the lease groups, at our election, by delivering cash to the third party or by delivering shares of common stock to the third party s affiliate. Any shares of common stock delivered to the third party s affiliate will generally be valued at the average of the daily-volume weighted average price of the common stock for each day in the 10-business day period beginning on the business day immediately after the date on which we notify the third party of our election to exercise the option (such amount not to exceed the daily-volume weighted average price of the common stock for either the first or last business day in such period). Our option to purchase leases under this arrangement has expired.

Under the Land Agreement, we issued warrants to purchase 57,461 shares of common stock in 2010, warrants to purchase 28,576 shares of common stock in 2011 and warrants to purchase 6,983 shares of common stock in January 2012.

Effects of Inflation and Changes in Price

Our results of operations and cash flows are affected by changing oil and gas prices. The significant decline in natural gas prices since mid-2008 and the continued depressed price of natural gas has resulted in a significant decline in revenue per unit of production. Although operating costs have also declined, the rate of decline in natural gas prices has been substantially greater. Historically, inflation has had a minimal effect on us. However, with interest rates at historic lows and the government attempting to stimulate the economy through rapid expansion of the money supply in recent years, inflation could become a significant issue in the future.

Recently Adopted Accounting Pronouncements

In January 2010, the FASB issued Accounting Standards Update No. 2010-03 to align the oil and gas reserve estimation and disclosure requirements of Topic 932 (Extractive Industries Oil and Gas) with the requirements of SEC Release 33-8994. This release is effective for financial statements issued on or after January 1, 2010. We adopted this guidance effective December 31, 2009. This release changes the accounting and disclosure requirements of oil and gas reserves and is intended to modernize and update the oil and gas disclosure requirements, to align them with current industry practices and to adapt to changes in technology. The new rules permit the use of new technologies to determine proved reserves, allow companies to disclose their probable and possible reserves and allow proved undeveloped reserves to be maintained beyond a five-year period only if justified by specific circumstances. The new rules require companies to report the independence and qualification of the person primarily responsible for the preparation or audit of its reserve estimates, and to file reports when a third party is relied upon to prepare or audit its reserve estimates. The new rules also require that the net present value of oil and gas reserves, which is used in the determination of the cost center ceiling, be based upon average market prices for oil and gas on the first calendar day of each month during the preceding 12-month period prior to the end of the current reporting period.

Summary of Critical Accounting Policies

The following summarizes our critical accounting policies. See a complete list of significant accounting policies in Note 2 to our consolidated financial statements.

Use of Estimates

The preparation of financial statements in conformity with U.S. generally accepted accounting principles requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosures of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenues and expenses during the periods reported. Actual results could differ from these estimates. We evaluate subsequent events through the date the financial statements are issued.

Significant estimates include volumes of proved oil and gas reserves which are used in calculating the amortization of proved oil and gas property costs, the present value of future net revenues included in the full cost ceiling test, estimates of future taxable income used in assessing the realizability of deferred tax assets, and asset retirement obligations. Other significant estimates include the, impairment of unproved properties, fair values of derivative instruments, stock-based compensation, the collectability of outstanding receivables, and contingencies. Proved oil and gas reserve estimates have numerous inherent uncertainties. The accuracy of any reserve estimate is a function of the quality and quantity of available data and the application of engineering and geological interpretation and judgment to available data. Subsequent drilling results, testing and production may justify revisions of such estimates. Accordingly, proved oil and gas reserve estimates are often different from the quantities of oil and gas that are ultimately recovered. In addition, proved oil and gas reserve estimates are vulnerable to changes in market prices of oil and gas. Such prices have been volatile in the past and can be expected to be volatile in the future.

Estimates are based on current assumptions that may be materially affected by changes to future economic conditions such as the market prices of oil and gas, the credit worthiness of counterparties, interest rates and the market value and volatility of the Company s common stock. Future changes in these assumptions may affect these significant estimates materially in the near term.

Oil and Gas Properties

Oil and gas properties are accounted for using the full cost method of accounting under which all productive and nonproductive costs directly associated with property acquisition, exploration and development activities are capitalized to costs centers established on a country-by-country basis. Internal costs directly identified with acquisition, exploration and development activities are capitalized and totaled $9.6 million, $5.3 million and $5.6 million for the years ended December 31, 2011, 2010, and 2009, respectively. Costs related to production, general corporate overhead or similar activities are expensed as incurred.

Capitalized oil and gas property costs within a cost center are amortized on an equivalent unit-of-production method, converting oil and natural gas liquids to gas equivalents at the ratio of one barrel of oil or natural gas liquids to six thousand cubic feet of gas, which represents their approximate relative energy content. The equivalent unit-of-production rate is computed on a quarterly basis by dividing production by proved oil and gas reserves at the beginning of the quarter which is applied to capitalized oil and gas property costs, which includes estimated asset retirement costs, less accumulated amortization, plus the estimated future expenditures (based on current costs) to be incurred in developing proved reserves, net of estimated salvage values. Average DD&A per Mcfe was $1.85, $1.25 and $1.55 for the years ended December 31, 2011, 2010 and 2009, respectively.

Costs not subject to amortization include unevaluated leasehold costs, seismic costs associated with specific unevaluated properties, related capitalized interest and the cost of exploratory wells in progress. Significant costs are assessed individually on a quarterly basis to determine whether or not and to what extent proved reserves have been assigned to the properties or if an impairment has occurred, in which case the related costs are added to the oil and gas property costs subject to amortization. Factors the Company considers in its impairment assessment include drilling results by the Company and other operators, the terms of oil and gas leases not held by production and drilling capital expenditure plans. We expect to complete the evaluation of the majority of our unproved properties within the next two to five years. Insignificant costs are grouped by major area and added to the oil and gas property costs subject to amortization based on the average primary lease terms of the properties. We capitalized interest costs associated with our unevaluated leasehold and seismic costs of $23.4 million, $20.7 million and $19.7 million for the years ended December 31, 2011, 2010 and 2009, respectively. Interest is capitalized using a weighted-average interest rate based on outstanding borrowings.

Proceeds from the sale of oil and gas properties are accounted for as reductions of capitalized costs with no gain or loss recognized, unless the sale significantly alters the relationship between capitalized costs and proved reserves of oil and gas attributable to a cost center. We have not had any sales of oil and gas properties that significantly alter that relationship.

Capitalized costs, less accumulated amortization and related deferred income taxes, are limited to the cost center ceiling equal to (1) the sum of (A) the present value of estimated future net revenues from proved oil and gas reserves, less estimated future expenditures to be incurred in developing and producing the proved reserves computed using a discount factor of 10%, (B) the costs of properties not subject to amortization, and (C) the lower of cost or estimated fair value of unproved properties included in the costs being amortized; less (2) related income tax effects. If the net capitalized costs exceed the cost center ceiling, the excess is recognized as an impairment of oil and gas properties. An impairment recognized in one period may not be reversed in a subsequent period even if higher oil and gas prices increase the cost center ceiling applicable to the subsequent period.

We recognized impairments of oil and gas properties at December 31, 2009 and March 31, 2009. The December 31, 2009 impairment of oil and gas properties of $122.5 million was based on crude oil and condensate prices of $56.10 per barrel, natural gas liquids prices of $23.18 per barrel and natural gas prices of $3.30 per Mcf, which represent the unweighted average market prices of crude oil and condensate, natural gas liquids and natural gas prices on the first calendar day of each month during the 12-month period ended December 31, 2009, as required by the oil and gas reserve estimation and disclosure requirements adopted effective December 31,2009.

The March 31, 2009 impairment of oil and gas properties of $216.4 million was based on crude oil and condensate prices of $45.13 per barrel, natural gas liquids prices of $18.92 per barrel and natural gas prices of $2.73 per Mcf, which represent the market prices as of May 6, 2009. The oil and gas reserve estimation and disclosure requirements in effect at the time allowed the use of market prices subsequent to the balance sheet date for purposes of calculating the impairment of oil and gas properties. The requirement to use market prices in effect on the balance sheet date with the option to use market prices subsequent to the balance sheet date was superseded by the new requirements that the Company adopted effective December 31, 2009, as discussed above.

The cost center ceiling exceeded our net capitalized costs for the U.S. cost center at December 31, 2010 by approximately $208.0 million and was based on crude oil and condensate prices of $72.13 per barrel, natural gas liquids prices of $35.18 per barrel and natural gas prices of $3.47 per Mcf (or a volume weighted average price of $4.37 per Mcfe), representing the unweighted average market prices on the first calendar day of each month during the 12-month period ended December 31, 2010. A ten percent increase in average market prices at December 31, 2010 would have increased the cost center ceiling by approximately $108.0 million and a ten percent decrease in average market prices would have decreased the cost center ceiling by approximately $172.0 million. This sensitivity analysis is as of December 31, 2010 and, accordingly, does not consider drilling results, production and prices subsequent to December 31, 2010 that may require revisions of proved reserve estimates.

The cost center ceiling exceeded our net capitalized costs for the U.S. cost center at December 31, 2011 by approximately $202.6 million and was based on crude oil and condensate prices of $92.76 per barrel, natural gas liquids prices of $44.90 per barrel and natural gas prices of $3.21 per Mcf (or a volume weighted average price of $5.38 per Mcfe), representing the unweighted average market prices on the first calendar day of each month during the 12-month period ended December 31, 2011. A ten percent increase in average market prices at December 31, 2011 would have increased the cost center ceiling by approximately $163.4 million and a ten percent decrease in average market prices would have caused an impairment of approximately $24.4 million. This sensitivity analysis is as of December 31, 2011 and, accordingly, does not consider drilling results, production and prices subsequent to December 31, 2011 that may require revisions of proved reserve estimates.

The cost center ceiling exceeded our net capitalized costs for the U.K. cost center at December 31, 2011 by approximately $124.5 million and was based on crude oil and condensate prices of $106.90 per barrel and natural gas prices of $7.54 per Mcf (or a volume weighted average price of $16.49 per Mcfe), representing the unweighted average market prices on the first calendar day of each month during the 12-month period ended December 31, 2011. A ten percent increase in average market prices at December 31, 2011 would have increased the cost center ceiling by approximately $19.0 million and a ten percent decrease in average market prices would have decreased the cost center ceiling by approximately $19.0 million. This sensitivity analysis is as of December 31, 2011 and, accordingly, does not consider drilling results, production and prices subsequent to December 31, 2011 that may require revisions of proved reserve estimates.

We have a significant amount of proved undeveloped reserves. We had 479.2 Bcfe, 437.8 Bcfe and 267.8 Bcfe of proved undeveloped reserves, representing 51%, 52% and 44% of our total proved reserves at December 31, 2011, 2010 and 2009, respectively. Approximately 285.9 Bcfe, or 60%, and 144.1 Bcfe, or 30%, of our proved undeveloped reserves at December 31, 2011, are attributable to the Barnett Shale and Eagle Ford Shale, respectively. We currently expect to drill wells associated with these undeveloped reserves within the next five years.

Because our depletion rate is based on the ratio of production to total proved reserves, we expect our relatively low historical depletion rate to continue until the level of undeveloped reserves in relation to total proved reserves is reduced through the development of existing undeveloped reserves and/or the significant addition of proved developed reserves through acquisition and/or exploration. If our level of total proved reserves and future development costs were to remain constant and average market prices were to decline, a lower depletion rate would result in an impairment of oil and gas properties earlier or to a larger extent than would a higher depletion rate.

Oil and Gas Reserve Estimates

The proved oil and gas reserve estimates as of December 31, 2011 included in this document have been prepared by Ryder Scott Company Petroleum Engineers, LaRoche Petroleum Consultants, Ltd., and Fairchild and Wells, Inc., independent third party reserve engineers. Reserve engineering is a subjective process of estimating underground accumulations of hydrocarbons that cannot be measured in an exact manner. The process relies on judgment and the interpretation of available geologic, geophysical, engineering and production data. The extent, quality and reliability of this data can vary. The process also requires assumptions regarding drilling and operating costs, taxes and availability of funds. The oil and gas reserve estimation and disclosure requirements mandate certain of these assumptions such as existing economic and operating conditions, average oil and gas prices and the discount rate.

Proved oil and gas reserve estimates prepared by others may be substantially higher or lower than our estimates. Significant assumptions used by the independent third party reserve engineers are assessed by our internal reserve team. All reserve reports prepared by the independent third party reserve engineers are reviewed by our senior management team, including the Chief Executive Officer and Chief Operating Officer. Because these estimates depend on many assumptions, all of which may differ from actual results, reserve quantities actually recovered may be significantly different than estimated. Material revisions to reserve estimates may be made depending on the results of drilling, testing, and production.

You should not assume that the present value of future net cash flows is the current market value of our estimated proved oil and gas reserves. In accordance with the oil and gas reserve estimation and disclosure requirements, the discounted future net cash flows from proved reserves are based on the unweighted average of the first day of the month price for each month in the previous twelve-month period, using current costs and a 10% discount rate.

Our depletion rate depends on our estimate of total proved reserves. If our estimates of total proved reserves increased or decreased, the depletion rate and therefore DD&A expense would decrease or increase, respectively. A 10% increase or decrease in our estimates of total proved reserves at December 31, 2011, would have decreased or increased our DD&A expense by approximately 9.0% or 10.9%, respectively, for the fourth quarter of 2011.

Derivative Instruments

We use derivative instruments, typically fixed-rate swaps, costless collars, puts, calls and basis differential swaps, to manage commodity price risk associated with a portion of our forecasted oil and gas production. Derivative instruments are recognized at their current fair value as assets or liabilities in the consolidated balance sheets. Although the derivative instruments provide an economic hedge of our exposure to commodity price risk associated with oil and gas production, because we elect not to meet the criteria to qualify our derivative instruments for hedge accounting treatment, unrealized gains and losses as a result of changes in the fair value of derivative instruments are recognized as gain (loss) on derivative instruments, net in the consolidated statements of operations. Realized gains and losses as a result of cash settlements with counterparties to our derivative instruments are also recorded as gain (loss) on derivative instruments, net in the consolidated statements of operations. We offset fair value amounts recognized for derivative instruments executed with the same counterparty and subject to master netting agreements.

Our Board of Directors establishes risk management policies and reviews derivative instruments, including volumes, types of instruments and counterparties, on a quarterly basis. These policies require that derivative instruments be executed only by the President or Chief Financial Officer after consultation with and concurrence by the President, Chief Financial Officer and Chairman of the Board. The master contracts with approved counterparties identify the President and Chief Financial Officer as the only Company representatives authorized to execute trades.

Income Taxes

Deferred income taxes are recognized at each reporting period for the future tax consequences of differences between the tax bases of assets and liabilities and their financial reporting amounts based on tax laws and statutory tax rates applicable to the periods in which the differences are expected to affect taxable income. We routinely assess the realizability of our deferred tax assets and consider our estimate of future taxable income based on production of proved reserves at estimated future pricing in making such assessments. If we conclude that it is more likely than not that some portion or all of the deferred tax assets will not be realized, the deferred tax assets are reduced by a valuation allowance. We classify interest and penalties associated with income taxes as interest expense.

Commitments and Contingencies

Liabilities are recognized for contingencies when (i) it is both probable that an asset has been impaired or that a liability has been incurred and (ii) that the amount of such loss is reasonably estimable.

Volatility of Oil and Gas Prices

Our revenues, future growth rate, results of operations, financial position and ability to borrow funds or obtain additional capital, as well as the carrying value of our oil and gas properties, are substantially dependent upon prevailing prices of oil and gas.

We review the carrying value of our oil and gas properties on a quarterly basis using the full cost method of accounting. See Summary of Critical Accounting Policies Oil and Gas Properties.

We rely on various types of derivative instruments to manage our exposure to commodity price risk and to provide a level of certainty in our forward cash flows supporting our capital expenditure program. The derivative instruments we typically use include fixed-rate swaps, costless collars, puts, calls and basis differential swaps. Under these derivative instruments, payments are received or made based on the differential between a fixed and a variable product price. These agreements are settled in cash at termination, expiration or exchanged for physical delivery contracts. Our current long-term strategy is to manage exposure for a substantial, but varying, portion of forecasted production up to 36 months. The derivative instruments are carried at fair value in the consolidated balance sheets, with the changes in fair value included in the consolidated statements of operations for the period in which the changes occur.

The fair value of derivative instruments at December 31, 2011 was a net asset of $37.3 million, 68% with Credit Suisse, 19% BNP Paribas, 6% with Shell Energy North America (US) LP, 5% with Credit Agricole, and the remaining 2% with Societe Generale. Master netting agreements are in place with these counterparties. Because the counterparties are either investment grade financial institutions or an investment grade international oil and gas company, we believe we have minimal credit risk and accordingly do not currently require our counterparties to post collateral to support the asset positions of our derivative instruments. As such, we are exposed to credit risk to the extent of nonperformance by the counterparties to our derivative instruments. Although we do not currently anticipate such nonperformance, we continue to monitor the financial viability of our counterparties. Because Credit Suisse, BNP Paribas, Credit Agricole, and Societe Generale are lenders in our revolving credit facility, we are not required to post collateral with respect to derivatives instrument in a net liability position with these counterparties as the contracts are secured by the revolving credit facility.

The following sets forth a summary of our natural gas derivative positions at average delivery location (WAHA and Houston Ship Channel) prices as of December 31, 2011.

Period	Volume (in MMbtu)	Weighted Average Floor Price ($/MMbtu)	Weighted Average Ceiling Price ($/MMbtu)
2012	18,943,000	$ 5.43	$ 5.56
2013	10,950,000	$ 5.07	$ 5.07

In connection with the derivative instruments above, we have entered into protective put spreads. In 2012, at market prices below the short put price of $4.77, the floor price becomes the market price plus the put spread of $1.28 on 7,572,000 of the 18,943,000 MMBtus and the remaining 11,370,600 MMBtus have a floor price of $5.43.

Period	Volume (in MMbtu)	Weighted Average Short Put Price ($/MMbtu)	Weighted Average Put Spread ($/MMbtu)
2012	7,572,400	$ 4.77	$ 1.28

In addition to the table above, we sold call positions of 3,650,000 MMBtus at a price of $5.50 per MMBtu for 2014.

The following sets forth a summary of our U.S. crude oil derivative positions at average NYMEX prices as of December 31, 2011.

Period	Volume (in Bbls)	Weighted Average Floor Price ($/Bbls)	Weighted Average Ceiling Price ($/Bbls)
2012	1,024,800	$ 82.57	$ 101.83
2013	839,500	$ 83.48	$ 102.55

For the years ended 2011, 2010 and 2009, we recorded the following gains and losses related to our oil and gas derivative instruments:

	Year Ended December 31,		
	2011	2010	2009
		(In thousands)	
Realized gain (loss) on derivative instruments, net	$ 35,452	$ 33,218	$ 74,866
Unrealized gain (loss) on derivative instruments, net	11,539	14,564	(33,401)
Gain on derivative instruments, net	$ 46,991	$ 47,782	$ 41,465

We deferred the payment of premiums associated with certain of our derivative instruments totaling a net liability of $1.2 million and $3.9 million at December 31, 2011 and December 31, 2010, respectively. We classified $0.4 million and $3.9 million as other current liabilities at December 31, 2011 and December 31, 2010, respectively, and $0.8 million as other non-current liabilities at December 31, 2011. There were no other non-current liabilities at December 31, 2010. These deferred premiums will be paid to the counterparty with each monthly settlement (April 2012 March 2014) and recognized as a reduction of realized gain (loss) on derivative instruments, net.

Item 7A. Qualitative and Quantitative Disclosures about Market Risk

Commodity Risk. Our primary market risk exposure is the commodity pricing applicable to our oil and gas production. The prices we realize on the sale of such production are primarily driven by the prevailing worldwide price for oil and spot prices of natural gas. The effects of such pricing volatility have been discussed above, and such volatility is expected to continue. A 10% fluctuation in the price received for oil and gas production would have an approximate $19.2 million impact on our revenues for the year ended December 31, 2011.

We rely on various types of derivative instruments to manage our exposure to commodity price risk and to provide a level of certainty in our forward cash flows supporting our capital expenditure program. The derivative instruments we typically use include fixed-rate swaps, costless collars, puts, calls and basis differential swaps. Our current long-term strategy is to manage exposure for a substantial, but varying, portion of forecasted production up to 36 months. We do not hold or issue derivative instruments for trading purposes. We realized gains on derivative instruments of $47.0 million, $47.8 million and $41.5 million for the years ended December 31, 2011, 2010, and 2009, respectively.

Financial Instruments and Debt Maturities. In addition to our derivative instruments, our other financial instruments include cash and cash equivalents, receivables, payables and current and long-term debt. The carrying amounts of cash and cash equivalents, receivables, payables and short-term debt approximate fair value due to the highly liquid or short-term nature of these instruments. The fair values of borrowings under our prior credit facility approximate the carrying amounts as of December 31, 2011, and were based upon interest rates currently available to us for borrowings with similar terms. The fair values of the Convertible Senior Notes and Senior Notes at December 31, 2011 were estimated at approximately $73.0 million and $606.0 million, respectively and were based on quoted market prices. As of December 31, 2011, scheduled maturities of long-term debt are $73.8 million in 2013 and $600.0 million in 2018.

Item 8. Financial Statements and Supplementary Data

The financial statements and information required by this Item appears on pages F-1 through F-44 of this Annual Report on Form 10-K.

Item 9. Changes In and Disagreements With Accountants on Accounting and Financial Disclosures

None.

Item 9A. Controls and Procedures

(a) Disclosure Controls and Procedures. We maintain disclosure controls and procedures that are designed to provide reasonable assurance that information required to be disclosed by us in the reports that we file or submit to the Securities and Exchange Commission (the SEC) under the Securities Exchange Act of 1934, as amended (the Exchange Act), is recorded, processed, summarized and reported within the time periods specified by the SEC s rules and forms, and that information is accumulated and communicated to our management, including our Chief Executive Officer and Chief Financial Officer, as appropriate to allow timely decisions regarding required disclosure.

In accordance with Rules 13a-15(b) and 15d-15(b) under the Exchange Act, we carried out an evaluation, under the supervision and with the participation of management, including our Chief Executive Officer and Chief Financial Officer, of the effectiveness of our disclosure controls and procedures (as defined by Rules 13a-15(e) and 15d-15(e) under the Exchange Act) as of the end of the period covered by this Annual Report on Form 10-K. As described below under paragraph (b) within Management s Annual Report on Internal Control over Financial Reporting, our Chief Executive Officer and Chief Financial Officer have concluded that, as of the end of the period covered by this Annual Report on Form 10-K, our disclosure controls and procedures were effective to provide reasonable assurance that information required to be disclosed by us in the reports that we file or submit to the SEC under the Exchange Act is recorded, processed, summarized and reported within the time periods specified by the SEC s rules and forms and that such information is accumulated and communicated to our management, including our Chief Executive Officer and Chief Financial Officer, as appropriate to allow timely decisions regarding required disclosure.

The audit report of KPMG, LLP, which is included in this Annual Report on Form 10-K, expressed an unqualified opinion on our consolidated financial statements.

(b) Management s Annual Report on Internal Control over Financial Reporting. Our management is responsible for establishing and maintaining adequate internal control over financial reporting as defined in Rules 13a-15(f) and 15d-15(f) under the Exchange Act. Our internal control over financial reporting is 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. Our internal control over financial reporting includes those policies and procedures that:

- pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect our transactions and dispositions of our assets;

provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that our receipts and expenditures are being made only in accordance with authorizations of our management and directors; and

provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of our assets that could have a material effect on the financial statements.

While reasonable assurance is a high level of assurance, it does not mean absolute assurance. Because of its inherent limitations, internal control over financial reporting may not prevent or detect every misstatement and instance of fraud. Controls are susceptible to manipulation, especially in instances of fraud caused by collusion of two or more people, including our senior management. 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.

Under the supervision and with the participation of our Chief Executive Officer and Chief Financial Officer, our management conducted an evaluation of the effectiveness of our internal control over financial reporting as of December 31, 2011. In making this evaluation, management used the *Internal Control Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). Based on the results of our evaluation, our management concluded that our internal control over financial reporting was effective as of December 31, 2011.

KPMG LLP, our independent registered public accounting firm that audited our consolidated financial statements, has also issued its own attestation report on the effectiveness of our internal control over financial reporting as of December 31, 2011, which is filed with this Annual Report on Form 10-K.

(c) Changes in Internal Control over Financial Reporting. There have not been any changes in our internal control over financial reporting during the fiscal quarter ended December 31, 2011 that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

Item 9B. Other Information

None.

PART III

Item 10. Directors, Executive Officers and Corporate Governance

The information required by this item is incorporated herein by reference to our definitive Proxy Statement (the 2012 Proxy Statement) for our 2012 annual meeting of shareholders. The 2012 Proxy Statement will be filed with the SEC not later than 120 days subsequent to December 31, 2011.

Item 11. Executive Compensation

The information required by this item is incorporated herein by reference to the 2012 Proxy Statement, which will be filed with the SEC not later than 120 days subsequent to December 31, 2011.

Item 12. Security Ownership of Certain Beneficial Owners and Management and Related Shareholder Matters

The information required by this item is incorporated herein by reference to the 2012 Proxy Statement, which will be filed with the SEC not later than 120 days subsequent to December 31, 2011.

Item 13. Certain Relationships and Related Transactions, and Director Independence

The information required by this item is incorporated herein by reference to the 2012 Proxy Statement, which will be filed with the SEC not later than 120 days subsequent to December 31, 2011.

Item 14. Principal Accountant Fees and Services

The information required by this item is incorporated herein by reference to the 2012 Proxy Statement, which will be filed with the SEC not later than 120 days subsequent to December 31, 2011.

PART IV

Item 15. Exhibits and Financial Statement Schedules
(a)(1) Financial Statements

The response to this item is submitted in a separate section of this Annual Report on Form 10-K.

(a)(2) Financial Statement Schedules

None.

(a)(3) Exhibits

EXHIBIT INDEX

Exhibit Number	Description
3.1	Amended and Restated Articles of Incorporation of the Company (incorporated herein by reference to Exhibit 3.1 to the Company s Annual Report on Form 10-K for the year ended December 31, 1997).
3.2	Articles of Amendment to Amended and Restated Articles of Incorporation (incorporated herein by reference to Exhibit 3.1 to the Company s Current Report on Form 8-K filed on June 25, 2008).
3.3	Amended and Restated Bylaws of the Company (incorporated herein by reference to Exhibit 3.1 to the Company s Current Report on Form 8-K filed on January 3, 2008).
4.1	Indenture among Carrizo Oil & Gas, Inc., the subsidiaries named therein and Wells Fargo Bank, National Association, as trustee, dated May 28, 2008 (incorporated herein by reference to Exhibit 4.1 to the Company s Current Report on Form 8-K filed on May 28, 2008).
4.2	First Supplemental Indenture dated May 28, 2008 between Carrizo Oil & Gas, Inc. and Wells Fargo Bank, National Association, as trustee (incorporated herein by reference to Exhibit 4.2 to the Company s Current Report on Form 8-K filed on May 28, 2008).
4.3	Second Supplemental Indenture dated May 14, 2009 among Carrizo Oil & Gas, Inc., the subsidiaries named therein and Wells Fargo Bank, National Association, as trustee (incorporated herein by reference to Exhibit 4.21 to the Company s Registration Statement on Form S-3 (Registration No. 333-159237)).
4.4	Fourth Supplemental Indenture dated November 2, 2010 among Carrizo Oil & Gas, Inc. the subsidiary guarantors named therein and Wells Fargo Bank, National Association, as trustee (incorporated herein by reference to Exhibit 4.2 to the Company s Current Report on Form 8-K filed on November 2, 2010).
4.5	Fifth Supplemental Indenture dated November 2, 2010 among Carrizo Oil & Gas, Inc. the subsidiary guarantors named therein and Wells Fargo Bank, National Association, as trustee (incorporated herein by reference to Exhibit 4.3 to the Company s Current Report on Form 8-K filed on November 2, 2010).
4.6	Sixth Supplemental Indenture dated May 4, 2011 among Carrizo Oil & Gas, Inc. the subsidiary guarantors named therein and Wells Fargo Bank, National Association, as trustee (incorporated herein by reference to Exhibit 4.1 to the Company s Quarterly Report on Form 10-Q for the quarter ended March 31, 2011).
4.7	

Seventh Supplemental Indenture dated May 4, 2011 among Carrizo Oil & Gas, Inc. the subsidiary guarantors named therein and Wells Fargo Bank, National Association, as trustee (incorporated herein by reference to Exhibit 4.2 to the Company s Quarterly Report on Form 10-Q for the quarter ended March 31, 2011).

	4.8	Eighth Supplemental Indenture dated August 5, 2011 among Carrizo Oil & Gas, Inc. the subsidiary guarantors named therein and Wells Fargo Bank, National Association, as trustee (incorporated herein by reference to Exhibit 4.3 to the Company s Quarterly Report on Form 10-Q for the quarter ended June 30, 2011).
	4.9	Ninth Supplemental Indenture dated August 5, 2011 among Carrizo Oil & Gas, Inc. the subsidiary guarantors named therein and Wells Fargo Bank, National Association, as trustee (incorporated herein by reference to Exhibit 4.4 to the Company s Quarterly Report on Form 10-Q for the quarter ended June 30, 2011).
	4.10	Officers Certificate of the Company dated as of November 17, 2011 (incorporated herein by reference to Exhibit 4.5 to the Company s Current Report on Form 8-K filed on November 17, 2011).
	4.11	Form of Warrant issued pursuant to Land Agreement dated November 24, 2009 (incorporated herein by reference to Exhibit 4.3 to the Company s Quarterly Report on Form 10-Q for the quarter ended March 31, 2011)
*	10.1	Amended and Restated Incentive Plan of the Company effective as of April 30, 2009 (incorporated herein by reference to Exhibit 10.2 to the Company s Current Report on Form 8-K filed on May 6, 2009).
*	10.2	Amended and Restated Employment Agreement between the Company and S.P. Johnson IV (incorporated herein by reference to Exhibit 10.2 to the Company s Current Report on Form 8-K filed on June 9, 2009).
*	10.3	Amended and Restated Employment Agreement between the Company and Paul F. Boling (incorporated herein by reference to Exhibit 10.3 to the Company s Current Report on Form 8-K filed on June 9, 2009).
*	10.4	Amended and Restated Employment Agreement between the Company and J. Bradley Fisher (incorporated herein by reference to Exhibit 10.4 to the Company s Current Report on Form 8-K filed on June 9, 2009).
*	10.5	Amended and Restated Employment Agreement between the Company and Gregory E. Evans (incorporated herein by reference to Exhibit 10.5 to the Company s Current Report on Form 8-K filed on June 9, 2009).
*	10.6	Amended and Restated Employment Agreement between the Company and Richard H. Smith (incorporated herein by reference to Exhibit 10.6 to the Company s Current Report on Form 8-K filed on June 9, 2009).
*	10.7	Employment Agreement between the Company and David L. Pitts (incorporated herein by reference to Exhibit 10.1 to the Company s Current Report on Form 8-K filed on January 20, 2010).
*	10.8	Form of Stock Option Award Agreement (incorporated herein by reference to Exhibit 10.43 to the Company s Annual Report on Form 10-K for the year ended December 31, 2004).
*	10.9	Form of Director Restricted Stock Award Agreement under the Incentive Plan of Carrizo Oil & Gas, Inc. (incorporated herein by reference to Exhibit 10.1 to the Company s Current Report on Form 8-K filed on April 22, 2005).
*	10.10	Form of Director Restricted Stock Award Agreement under the Incentive Plan of Carrizo Oil & Gas, Inc. (incorporated herein by reference to Exhibit 10.2 to the Company s Current Report on Form 8-K filed on April 22, 2005).
*	10.11	Form of Employee Restricted Stock Award Agreement under the Incentive Plan of Carrizo Oil & Gas, Inc. (incorporated herein by reference to Exhibit 10.3 to the Company s Current Report on Form 8-K filed on April 22, 2005).
*	10.12	Form of 2010 Employee Restricted Stock Unit Award Agreement (with performance-based vesting and time-based vesting) (incorporated herein by reference to Exhibit 10.12 to the Company s Annual Report on Form 10-K for the year ended December 31, 2010).
*	10.13	Form of 2009 Employee Restricted Stock Unit Award Agreement (with performance-based vesting only) (incorporated herein by reference to Exhibit 10.8 to the Company s Current Report on Form 8-K filed on June 9, 2009).
*	10.14	Form of 2010 Employee Cash Settled Stock Appreciation Rights Award Agreement under the Carrizo Oil & Gas, Inc. Incentive Plan (incorporated herein by reference to Exhibit 10.14 to the Company s Annual Report on Form 10-K for the year ended December 31, 2010).

*	10.15	Form of 2009 Employee Cash or Stock Settled Stock Appreciation Rights Award Agreement under the Carrizo Oil & Gas, Inc. Incentive Plan (incorporated herein by reference to Exhibit 10.9 to the Company s Current Report on Form 8-K filed on June 9, 2009).
*	10.16	Carrizo Oil & Gas, Inc. Cash-Settled Stock Appreciation Rights Plan (incorporated herein by reference to Exhibit 10.10 to the Company s Current Report on Form 8-K filed on June 9, 2009).
*	10.17	Form of 2009 Employee Cash-Settled Stock Appreciation Rights Award Agreement pursuant to the Carrizo Oil & Gas, Inc. Cash-Settled Stock Appreciation Rights Plan (incorporated herein by reference to Exhibit 10.11 to the Company s Current Report on Form 8-K filed on June 9, 2009).
*	10.18	Form of Independent Contractor Restricted Stock Award Agreement (incorporated herein by reference to Exhibit 10.4 to the Company s Current Report on Form 8-K filed on May 30, 2006).
*	10.19	Form of Employee Restricted Stock Award Agreement (with performance-based vesting) (incorporated herein by reference to Exhibit 10.6 to the Company s Current Report on Form 8-K filed on December 23, 2008).
	10.20	S Corporation Tax Allocation, Payment and Indemnification Agreement among the Company and Messrs. Loyd, Webster, Johnson, Hamilton and Wojtek (incorporated herein by reference to Exhibit 10.8 to the Company s Registration Statement on Form S-1 (Registration No. 333-29187)).
	10.21	S Corporation Tax Allocation, Payment and Indemnification Agreement among Carrizo Production, Inc. and Messrs. Loyd, Webster, Johnson, Hamilton and Wojtek (incorporated herein by reference to Exhibit 10.9 to the Company s Registration Statement on Form S-1 (Registration No. 333-29187)).
	10.22	Amended and Restated Registration Rights Agreement dated December 15, 1999 among the Company, Paul B. Loyd Jr., Douglas A. P. Hamilton, Steven A. Webster, S.P. Johnson IV, Frank A. Wojtek and DAPHAM Partnership, L.P. (incorporated herein by reference to Exhibit 99.5 to the Company s Current Report on Form 8-K dated December 15, 1999).
	10.23	Registration Rights Agreement dated February 20, 2002 among the Company, Mellon Ventures, L.P. and Steven A. Webster (incorporated herein by reference to Exhibit 99.5 to the Company s Current Report on Form 8-K dated February 20, 2002).
	10.24	Credit Agreement dated as of January 27, 2011 among Carrizo Oil & Gas, Inc., as Borrower, BNP Paribas, as Administrative Agent, Credit Agricole Corporate and Investment Bank and Royal Bank of Canada, as Co-Syndication Agents, Capital One, N.A. and Compass Bank, as Co-Documentation Agents, BNP Paribas Securities Corp. as Sole Lead Arranger and Sole Bookrunner, and the Lenders party thereto (incorporated herein by reference to Exhibit 10.1 to the Company s Current Report on Form 8-K filed on February 2, 2011).
	10.25	Senior Secured Multicurrency Credit Facility Agreement dated as of January 28, 2011 among Carrizo UK Huntington Ltd., as Borrower, Carrizo Oil & Gas, Inc., as Parent, and BNP Paribas and SocieteGenerale as Lead Arrangers, Bookrunners and Original Lenders (incorporated herein by reference to Exhibit 10.2 to the Company s Current Report on Form 8-K filed on February 2, 2011).
	10.26	Form of Indemnification Agreement between the Company and each of its directors and executive officers (incorporated herein by reference to Exhibit 10.6 to the Company s Annual Report on Form 10-K for the year ended December 31, 1998).
	10.27	Form of Amendment to Director Indemnification Agreement (incorporated herein by reference to Exhibit 99.8 to the Company s Current Report a Form 8-K dated February 20, 2002).
	10.28	Omnibus Amendment among Carrizo (Marcellus) LLC, Carrizo Oil & Gas, Inc., Avista Capital Partners II, L.P. and ACP II Marcellus LLC, dated as of September 10, 2010 (incorporated herein by reference to Exhibit 10.3 to the Company s Current Report on Form 8-K filed on September 16, 2010).
	10.29	Amended and Restated Participation Agreement, dated as of November 16, 2010, and effective as of October 1, 2010, among Carrizo (Marcellus) WV LLC, Carrizo Oil & Gas, Inc., Avista Capital Partners II, L.P. and ACP II Marcellus LLC (incorporated herein by reference to Exhibit 10.1 to the Company s Current Report on Form 8-K filed on November 19, 2010).

21.1	Subsidiaries of the Company.
23.1	Consent of KPMG LLP.
23.2	Consent of Fairchild and Wells, Inc.
23.3	Consent of LaRoche Petroleum Consultants, Ltd.
23.4	Consent of Ryder Scott Company Petroleum Engineers (U.S.).
23.5	Consent of Ryder Scott Company Petroleum Engineers (U.K.).
31.1	CEO Certification Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
31.2	CFO Certification Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
32.1	CEO Certification Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
32.2	CFO Certification Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
99.1	Summary of Reserve Report and Report of Ryder Scott Company Petroleum Engineers as of December 31, 2011 (U.S.).
99.2	Summary of Reserve Report and Report of Ryder Scott Company Petroleum Engineers as of December 31, 2011 (U.K.).
99.3	Summary of Reserve Report and Report of Fairchild and Wells, Inc. as of December 31, 2011.
99.4	Summary of Reserve Report and Report of LaRoche Petroleum Consultants, Ltd. as of December 31, 2011.

Incorporated by reference as indicated.

* Management contract or compensatory plan or arrangement.

INDEX TO CONSOLIDATED FINANCIAL STATEMENTS

Report of Independent Registered Public Accounting Firm

The Board of Directors and Shareholders

Carrizo Oil & Gas, Inc.:

We have audited the accompanying consolidated balance sheets of Carrizo Oil & Gas, Inc. and subsidiaries as of December 31, 2011 and 2010, and the related consolidated statements of operations, shareholders equity, and cash flows for each of the years in the three-year period ended December 31, 2011. These consolidated financial statements are the responsibility of the Company s management. Our responsibility is to express an opinion on these consolidated financial statements based on our audits.

We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. 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 Carrizo Oil & Gas, Inc. and subsidiaries as of December 31, 2011 and 2010, and the results of their operations and their cash flows for each of the years in the three-year period ended December 31, 2011, in conformity with U.S. generally accepted accounting principles.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), Carrizo Oil & Gas, Inc. s internal control over financial reporting as of December 31, 2011, 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 February 29, 2012 expressed an unqualified opinion on the effectiveness of the Company s internal control over financial reporting.

/s/ KPMG LLP

Houston, Texas

February 29, 2012

Report of Independent Registered Public Accounting Firm

The Board of Directors and Shareholders

Carrizo Oil & Gas, Inc.:

We have audited Carrizo Oil & Gas Inc. s internal control over financial reporting as of December 31, 2011, based on criteria established in *Internal Control Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). Carrizo Oil & Gas Inc. 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 Management s Report on Internal Control over Financial Reporting as presented within Item 9A. *Controls and Procedures*. 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, and testing and evaluating the design and operating effectiveness of internal control based on the assessed risk. Our audit also included 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, Carrizo Oil & Gas, Inc. maintained, in all material respects, effective internal control over financial reporting as of December 31, 2011, based on criteria established in *Internal Control Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the consolidated balance sheets of Carrizo Oil & Gas, Inc. and subsidiaries as of December 31, 2011 and 2010, and the related consolidated statements of operations, shareholders equity, and cash flows for each of the years in the three-year period ended December 31, 2011, and our report dated February 29, 2012 expressed an unqualified opinion on those consolidated financial statements.

/s/ KPMG LLP

Houston, Texas

February 29, 2012

CARRIZO OIL & GAS, INC.

CONSOLIDATED BALANCE SHEETS

	December 31, 2011	December 31, 2010
	(In thousands, except per share amount)	
ASSETS		
CURRENT ASSETS		
Cash and cash equivalents	$ 28,112	$ 4,128
Accounts receivable, net		
Oil and gas sales	21,988	16,027
Joint interest billing	31,050	14,309
Other	1,740	560
Advances to operators	97	487
Fair value of derivative instruments	27,877	17,698
Prepaids and other current assets	9,533	7,123
Total current assets	120,397	60,332
PROPERTY AND EQUIPMENT, NET		
Oil and gas properties using the full cost method of accounting		
Proved oil and gas properties, net	907,347	626,665
Costs not subject to amortization	394,429	352,479
Other property and equipment, net	8,738	3,913
TOTAL PROPERTY AND EQUIPMENT, NET	1,310,514	983,057
DEFERRED FINANCING COSTS, NET	23,217	14,670
INVESTMENTS	2,523	3,392
FAIR VALUE OF DERIVATIVE INSTRUMENTS	9,617	7,257
DEFERRED INCOME TAXES	59,755	72,587
INVENTORY		1,646
OTHER ASSETS	1,657	1,193
TOTAL ASSETS	$ 1,527,680	$ 1,144,134
LIABILITIES AND SHAREHOLDERS EQUITY		
CURRENT LIABILITIES		
Accounts payable, trade	$ 25,672	$ 33,653
Revenue and royalties payable	54,600	23,864
Current state tax payable	1,048	4,052
Accrued drilling costs	92,179	26,884
Accrued interest	12,059	5,953
Other accrued liabilities	21,414	11,838
Advances for joint operations	54,179	3,407
Current maturities of long-term debt		160
Deferred income taxes	9,685	5,286
Other current liabilities	484	3,907
Total current liabilities	271,320	119,004
LONG-TERM DEBT, NET OF CURRENT MATURITIES AND DEBT DISCOUNT	729,300	558,094
ASSET RETIREMENT OBLIGATIONS	11,242	6,369

FAIR VALUE OF DERIVATIVE INSTRUMENTS	9	715
OTHER LIABILITIES	5,954	3,316
COMMITMENTS AND CONTINGENCIES		
SHAREHOLDERS EQUITY		
Common stock, $0.01 par value (90,000 shares authorized, 39,563 and 38,906 shares issued and outstanding at December 31, 2011 and 2010, respectively)	395	389
Additional paid-in capital	647,429	630,845
Accumulated deficit	(137,969)	(174,598)
Total shareholders equity	509,855	456,636
TOTAL LIABILITIES AND SHAREHOLDERS EQUITY	$ 1,527,680	$ 1,144,134

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

CARRIZO OIL & GAS, INC.

CONSOLIDATED STATEMENTS OF OPERATIONS

	For the Years Ended December 31, 2011	2010	2009
	(In thousands, except per share amounts)		
OIL AND GAS REVENUES	$ 202,167	$ 138,123	$ 112,699
COSTS AND EXPENSES			
Lease operating	28,314	23,659	25,167
Production tax	5,697	3,648	132
Ad valorem tax	3,625	3,707	5,022
Depreciation, depletion and amortization	84,606	47,030	52,005
Impairment of oil and gas properties		2,731	338,914
General and administrative (inclusive of stock-based compensation expense of $11,864, $16,608 and $11,297 for the years ended December 31, 2011, 2010 and 2009, respectively)	41,781	35,906	30,136
Accretion expense related to asset retirement obligations	311	216	308
TOTAL COSTS AND EXPENSES	164,334	116,897	451,684
OPERATING INCOME (LOSS)	37,833	21,226	(338,985)
OTHER INCOME AND EXPENSES			
Gain (loss) on derivative instruments, net	46,991	47,782	41,465
Loss on extinguishment of debt	(897)	(31,023)	
(Impairment) recovery of investment in Pinnacle		165	(2,091)
Interest expense	(52,803)	(43,264)	(38,286)
Capitalized interest	23,369	20,746	19,696
Other income, net	356	47	49
INCOME (LOSS) BEFORE INCOME TAXES	54,849	15,679	(318,152)
INCOME TAX (EXPENSE) BENEFIT	(18,220)	(5,729)	113,307
NET INCOME (LOSS)	$ 36,629	$ 9,950	$ (204,845)
OTHER COMPREHENSIVE INCOME (LOSS), NET OF INCOME TAXES			
Increase in fair value of investment in Pinnacle, net of income taxes		17	55
Reclassification of cumulative (increase) decrease in fair value of investment in Pinnacle, net of income taxes		(106)	1,333
COMPREHENSIVE INCOME (LOSS)	$ 36,629	$ 9,861	$ (203,457)
NET INCOME (LOSS) PER COMMON SHARE			
BASIC	$ 0.94	$ 0.29	$ (6.61)
DILUTED	$ 0.92	$ 0.29	$ (6.61)
WEIGHTED AVERAGE COMMON SHARES OUTSTANDING			
BASIC	39,077	33,861	31,006
DILUTED	39,668	34,305	31,006

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

CARRIZO OIL & GAS, INC.

CONSOLIDATED STATEMENTS OF SHAREHOLDERS EQUITY

	Common Stock		Additional Paid-in Capital	Retained Earnings (Accumulated Deficit)	Accumulated Other Comprehensive Income (Loss)	Total Shareholders Equity
	Shares	Amount				
			(In thousands, except share amounts)			
BALANCE, January 1, 2009	30,859,647	$ 309	$ 420,778	$ 20,297	$ (1,299)	$ 440,085
Stock options exercised for cash	5,000		9			9
Stock-based compensation			10,543			10,543
Restricted stock awards and units issued, net of forfeitures	226,286	2	304			306
Other	9,500		123			123
Other comprehensive loss, net of income taxes						
Increase in fair value of investment in Pinnacle, net of income tax expense of $31					55	55
Reclassification of cumulative decrease in fair value of investment in Pinnacle, net of income tax benefit of $758					1,333	1,333
Net loss				(204,845)		(204,845)
Total comprehensive loss						(203,457)
BALANCE, December 31, 2009	31,100,433	$ 311	$ 431,757	$ (184,548)	$ 89	$ 247,609
Stock options exercised for cash	266,433	3	687			690
Stock-based compensation			10,290			10,290
Restricted stock awards and units issued, net of forfeitures	344,311	3	(1,101)			(1,098)
Common stock offerings, net of offering costs	7,195,000	72	188,462			188,534
Other			750			750
Other comprehensive income, net of income taxes						
Increase in fair value of investment in Pinnacle, net of income tax expense of $9					17	17
Reclassification of cumulative increase in fair value of investment in Pinnacle, net of income tax expense of $59					(106)	(106)
Net income				9,950		9,950
Total comprehensive income						9,861
BALANCE, December 31, 2010	38,906,177	$ 389	$ 630,845	$ (174,598)	$	$ 456,636
Stock options exercised for cash	151,500	1	47			48
Stock-based compensation			14,444			14,444
Restricted stock awards and units issued, net of forfeitures	439,237	4	(483)			(479)
Other	65,762	1	2,576			2,577
Other comprehensive income, net of income taxes						
Net income				36,629		36,629
Total comprehensive income						36,629
BALANCE, December 31, 2011	39,562,676	$ 395	$ 647,429	$ (137,969)	$	$ 509,855

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

CARRIZO OIL & GAS, INC.

CONSOLIDATED STATEMENTS OF CASH FLOWS

	For the Years Ended December 31,		
	2011	2010	2009
		(In thousands)	
CASH FLOWS FROM OPERATING ACTIVITIES			
Net income (loss)	$ 36,629	$ 9,950	$ (204,845)
Adjustments to reconcile net income (loss) to net cash provided by operating activities-			
Depreciation, depletion and amortization	84,606	47,030	52,005
Unrealized (gain) loss on derivative instruments	(11,539)	(14,564)	33,401
Impairment of oil and gas properties		2,731	338,914
Accretion related to asset retirement obligations	311	216	308
Loss on extinguishment of debt	897	31,023	
Stock-based compensation	11,864	16,608	11,297
Allowance for doubtful accounts	31	485	772
Deferred income taxes	17,155	1,493	(113,378)
Amortization of debt discount and deferred financing costs, net of amounts capitalized	3,383	7,716	5,898
Impairment (recovery) of investment in Pinnacle		(165)	2,091
Other, net	2,846	3,262	5,869
Changes in operating assets and liabilities-			
Accounts receivable	(23,910)	(10,040)	(656)
Accounts payable	33,457	913	558
Accrued liabilities	9,906	(69)	2,014
Other, net	(11,298)	(2,173)	(876)
Net cash provided by operating activities	154,338	94,416	133,372
CASH FLOWS FROM INVESTING ACTIVITIES			
Capital expenditures	(556,324)	(347,808)	(182,907)
Increase (decrease) in capital expenditure payables and accruals	52,373	22,540	(25,685)
Proceeds from sales of oil and gas properties, net	167,265	54,217	48,524
Advances to operators	390	53	(204)
Advances for joint operations	50,772	1,668	(2,076)
Other, net	(474)	(966)	(105)
Net cash used in investing activities	(285,998)	(270,296)	(162,453)
CASH FLOWS FROM FINANCING ACTIVITIES			
Proceeds from borrowings and issuances	921,096	916,308	128,113
Debt repayments	(752,660)	(917,148)	(96,461)
Payments of debt issuance and retirement costs	(12,839)	(12,213)	(3,927)
Proceeds from common stock offerings, net of offering costs		188,534	
Proceeds from stock options exercised	47	690	9
Net cash provided by financing activities	155,644	176,171	27,734
NET INCREASE (DECREASE) IN CASH AND CASH EQUIVALENTS	23,984	291	(1,347)
CASH AND CASH EQUIVALENTS, beginning of year	4,128	3,837	5,184
CASH AND CASH EQUIVALENTS, end of year	$ 28,112	$ 4,128	$ 3,837
SUPPLEMENTAL CASH FLOW DISCLOSURES			
Cash paid for interest, net of amounts capitalized	$ 26,077	$ 24,218	$ 16,347

Cash paid for income taxes	$	4,156	$	95	$	67

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

CARRIZO OIL & GAS, INC.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

1. NATURE OF OPERATIONS

Carrizo Oil & Gas, Inc. is a Houston-based independent energy company which, together with its subsidiaries (collectively, Carrizo , the Company or we), is actively engaged in the exploration, development, and production of oil and gas in the United States and United Kingdom. Our current operations are principally focused in proven, producing oil and gas plays primarily in the Eagle Ford Shale in South Texas, the Niobrara Formation in Colorado, the Barnett Shale in North Texas, the Marcellus Shale in Pennsylvania, New York and West Virginia, the Utica Shale in Ohio and Pennsylvania, and the U.K. North Sea where our Huntington Field development project is currently under development.

2. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Basis of Presentation and Principles of Consolidation

The consolidated financial statements include the accounts of the Company and its wholly-owned subsidiaries after elimination of all significant intercompany transactions and balances and are presented in accordance with U.S. generally accepted accounting principles (GAAP). The Company proportionately consolidates its undivided interests in oil and gas properties as well as investments in unincorporated entities, such as partnerships and LLCs where the Company, as a partner or member, has undivided interests in the oil and gas properties.

Reclassifications

Certain reclassifications have been made to prior period amounts to conform to the current period presentation. These reclassifications had no effect on total assets, total liabilities, total shareholders equity, net income (loss), comprehensive income (loss) or net cash provided by or used in operating, investing or financing activities.

Use of Estimates

The preparation of financial statements in conformity with GAAP requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosures of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenues and expenses during the periods reported. Actual results could differ from these estimates. The Company evaluates subsequent events through the date the financial statements are issued.

Significant estimates include volumes of proved oil and gas reserves which are used in calculating the amortization of proved oil and gas property costs, the present value of future net revenues included in the full cost ceiling test, estimates of future taxable income used in assessing the realizability of deferred tax assets, and asset retirement obligations. Other significant estimates include the impairment of unproved properties, fair values of derivative instruments, stock-based compensation, the collectability of outstanding receivables, and contingencies. Proved oil and gas reserve estimates have numerous inherent uncertainties. The accuracy of any reserve estimate is a function of the quality and quantity of available data and the application of engineering and geological interpretation and judgment to available data. Subsequent drilling results, testing and production may justify revisions of such estimates. Accordingly, proved oil and gas reserve estimates are often different from the quantities of oil and gas that are ultimately recovered. In addition, proved oil and gas reserve estimates are vulnerable to changes in average market prices of oil and gas. Such prices have been volatile in the past and can be expected to be volatile in the future.

Estimates are based on current assumptions that may be materially affected by changes to future economic conditions such as the market prices of oil and gas, the creditworthiness of counterparties, interest rates and the market value and volatility of the Company s common stock. Future changes in these assumptions may affect these significant estimates materially in the near term.

Cash and Cash Equivalents

Cash and cash equivalents include highly liquid investments with original maturities of three months or less.

Accounts Receivable and Allowance for Doubtful Accounts

The Company establishes an allowance for doubtful accounts when it determines that it will not collect all or a part of an accounts receivable balance. The Company assesses the collectability of its accounts receivable on a quarterly basis and adjusts the allowance as necessary using the specific identification method. A roll forward of the allowance for doubtful accounts is as follows (in thousands):

January 1, 2009	$ 1,264
Charged to general and administrative	772
December 31, 2009	2,036
Charged to general and administrative	485
Amounts written off	(51)
December 31, 2010	2,470
Charged to general and administrative	31
Amounts written off	(197)
December 31, 2011	$ 2,304

Concentration of Credit Risk

Substantially all of the Company s accounts receivable result from oil and gas sales, joint interest billings to third parties in the oil and gas industry or drilling and completion advances to third-party operators for development costs of wells in progress. This concentration of customers and joint interest owners may impact the Company s overall credit risk in that these entities may be similarly affected by changes in economic and other industry conditions. The Company does not require collateral from its customers. The Company generally has the right to offset revenue against related billings to joint interest owners.

Derivative instruments subject the Company to a concentration of credit risk. See Note 11. Derivative Instruments for further discussion of concentration of credit risk related to the Company s derivative instruments.

Major Customers

Sales to individual customers constituting 10% or more of total revenues were as follows:

	Year Ended December 31,		
	2011	**2010**	**2009**
DTE Energy Trading, Inc.	43%	63%	54%

Oil and Gas Properties

Oil and gas properties are accounted for using the full cost method of accounting under which all productive and nonproductive costs directly associated with property acquisition, exploration and development activities are capitalized to costs centers established on a country-by-country basis. Internal costs directly associated with acquisition, exploration and development activities are capitalized and totaled $9.6 million, $5.3 million, and $5.6 million for the years ended December 31, 2011, 2010, and 2009, respectively. Costs related to production, general corporate overhead and similar activities are expensed as incurred.

Capitalized oil and gas property costs within a cost center are amortized on an equivalent unit-of-production method, converting oil and natural gas liquids to gas equivalents at the ratio of one barrel of oil or natural gas liquids to six thousand cubic feet of gas, which represents their approximate relative energy content. The equivalent unit-of-production rate is computed on a quarterly basis by dividing production by proved oil and gas reserves at the beginning of the quarter then applying such amount to capitalized oil and gas property costs, which includes estimated asset retirement costs, less accumulated amortization, plus the estimated future expenditures (based on current costs) to be incurred in developing proved reserves, net of estimated salvage values. Averagedepreciation, depletion and amortization (DD&A) per Mcfe on oil and gas properties was $1.85, $1.25, and $1.55 for the years ended December 31, 2011, 2010 and 2009, respectively.

Costs not subject to amortization include unevaluated leasehold costs, seismic costs associated with specific unevaluated properties, related capitalized interest and the cost of exploratory wells in progress. Significant costs are assessed individually on a quarterly basis to determine whether or not and to what extent proved reserves have been assigned to the properties or if an impairment has occurred, in which case the related costs are added to the oil and gas property costs subject to amortization. Factors the Company considers in its impairment assessment include drilling results by the Company and other operators, the terms of oil and gas leases not held by production and drilling capital expenditure plans. The Company expects to complete its evaluation of the majority of its unproved properties within the next two to five years. Insignificant costs are grouped by major area and added to the oil and gas property costs subject to amortization based on the average primary lease term of the properties. The Company capitalized interest costs associated with its unevaluated leasehold and seismic costs of $23.4 million, $20.7 million, and $19.7 million for the years ended December 31, 2011, 2010 and 2009, respectively. Interest is capitalized on the average balance of unproved properties using a weighted-average interest rate based on outstanding borrowings.

Proceeds from the sale of oil and gas properties are recognized as a reduction of capitalized oil and gas property costs with no gain or loss recognized, unless the sale significantly alters the relationship between capitalized costs and proved reserves of oil and gas attributable to a cost center. The Company has not had any sales of oil and gas properties that significantly alter that relationship.

In connection with the formation of ACP II Marcellus LLC (ACP II), the Company s partner in one of its joint ventures in the Marcellus Shale, the Company was issued a class of interests (B Units) in ACP II. The B Units entitle the Company to certain percentages of cash distributions to affiliates of Avista Capital Partners, LP, (together with its affiliates, Avista), if, when and only to the extent that those cash distributions exceed certain internal rates-of-return and return-on-investment thresholds with respect to Avista s investment in ACP II as set forth in the limited liability company agreement of ACP II. Because the B Units do not provide the Company with an ownership interest in the oil and gas properties of ACP II, the Company is not required to pay for property acquisition, exploration or development costs associated with ACP II s ownership interest in oil and gas properties, nor do the B Units entitle the Company to recognize oil and gas production and therefore, proved reserves associated with ACP II s ownership interest in oil and gas properties. However, under the full cost method of accounting, cash distributions received on the B Units are considered proceeds from the sale of oil and gas properties which are recognized as a reduction of capitalized oil and gas property costs. See Note 10. Related Party Transactions.

Capitalized costs, less accumulated amortization and related deferred income taxes, are limited to the cost center ceiling equal to (i) the sum of (A) the present value of estimated future net revenues from proved oil and gas reserves, less estimated future expenditures to be incurred in developing and producing the proved reserves computed using a discount factor of 10%, (B) the costs of properties not subject to amortization, and (C) the lower of cost or estimated fair value of unproved properties included in the costs being amortized; less (ii) related income tax effects. If the net capitalized costs exceed the cost center ceiling, the excess is recognized as an impairment of oil and gas properties. An impairment recognized in one period may not be reversed in a subsequent period even if higher oil and gas prices increase the cost center ceiling applicable to the subsequent period.

The estimated future net revenues used in the ceiling test are calculated using average quoted market prices for sales of oil and gas on the first calendar day of each month during the preceding 12-month period prior to the end of the current reporting period. Prior to December 31, 2009, prices and costs used to calculate future net revenues were those as of the end of the appropriate quarterly period. Prices are held constant indefinitely and are not changed except where different prices are fixed and determinable from applicable contracts for the remaining term of those contracts. Prices used in the ceiling test computation do not include the impact of derivative instruments because the Company elected not to meet the criteria to qualify its derivative instruments for hedge accounting treatment.

Depreciation of other property and equipment is recognized using the straight-line method based on estimated useful lives ranging from five to ten years.

Deferred Financing Costs

Deferred financing costs were $23.2 million (net of $3.2 million of accumulated amortization) and $14.7 million (net of $6.3 million of accumulated amortization) as of December 31, 2011 and 2010, respectively and include legal fees, accounting fees, underwriting fees, printing costs, and other direct costs associated with the issuance of the debt instruments and costs associated with revolving credit facilities. The capitalized costs are amortized to interest expense using the effective interest method over the terms of the debt instruments or credit facilities, which is through October 2018 for the Company s 8.625% Senior Notes due 2018, May 2013 for the Company s 4.375% Convertible Senior Notes due 2028, January 2016 for the Revolving Credit Facility and December 2014 for the Huntington Facility. See Note 6. Debt.

Investments

Prior to the sale of its investment in Pinnacle Gas Resources, Inc. (Pinnacle) in January 2011 (see Note 3. Investments), the Company accounted for its investment in Pinnacle as available-for-sale and adjusted the book value to fair value through other comprehensive income (loss), net of income taxes. This fair value was assessed quarterly for other than temporary impairment based on publicly available information. If the impairment was deemed other than temporary, it was recognized in earnings. Subsequent recoveries in fair value were reflected as increases to investments and other comprehensive income (loss), net of income taxes.

The Company accounts for its investment in Oxane Materials, Inc. (Oxane) using the cost method of accounting and adjusts the carrying amount of its investment for contributions to and distributions from Oxane.

Financial Instruments

The Company s financial instruments consist of cash and cash equivalents, receivables, payables, derivative instruments and current and long-term debt. The carrying amounts of cash and cash equivalents, receivables, payables and short-term debt approximate fair value due to the highly liquid or short-term nature of these instruments. The fair values of derivative instruments are based on a third-party pricing model which utilizes inputs that include (a) quoted forward prices for oil and gas, (b) discount rates, (c) volatility factors and (d) current market and contractual prices, as well as other relevant economic measures. The carrying amount of long-term debt under the Prior Credit Facility, the Revolving Credit Facility and the Huntington Facility approximate fair value as these borrowings bear interest at variable rates of interest. The carrying amounts of the Senior Notes and the Convertible Senior Notes may not approximate fair value because the notes bear interest at fixed rates of interest. See Note 6. Debt and Note 12. Fair Value Measurements.

Asset Retirement Obligations

The Company s oil and gas properties require expenditures to plug and abandon wells after the reserves have been depleted. The asset retirement obligation is recognized when the well is drilled with an associated increase in oil and gas property costs. The asset retirement obligation is recorded at fair value and requires estimates of the costs to plug and abandon wells, the costs to restore the surface, the remaining lives of wells based on oil and gas reserve estimates and future inflation rates. The obligation is discounted using a credit-adjusted risk-free interest rate which is accreted over time to its expected settlement value. Estimated costs consider historical experience, third party estimates and state regulatory requirements and do not consider salvage values. At least annually, the Company reassesses the obligation to determine whether a change in the estimated obligation is necessary. On an interim basis, the Company reassesses the estimated cash flows underlying the obligation when indicators suggest the estimated cash flows underlying the obligation have materially changed.

Commitments and Contingencies

Liabilities are recognized for contingencies when (i) it is both probable that an asset has been impaired or that a liability has been incurred and (ii) the amount of such loss is reasonably estimable.

Revenue Recognition

Oil and gas revenues are recognized when the products are sold to a purchaser at a fixed or determinable price, delivery has occurred, title has transferred and collectability is reasonably assured. The Company follows the sales method of accounting for oil and gas revenues whereby revenue is recognized for all oil and gas sold to purchasers, regardless of whether the sales are proportionate to the Company s ownership interest in the property. Production imbalances are recognized as an asset or liability to the extent that the Company has an imbalance on a specific property that is in excess of its remaining proved oil and gas reserves. Oil and gas sales volumes are not significantly different from the Company s share of production and as of December 31, 2011 and 2010, the Company did not have any material production imbalances.

Derivative Instruments

The Company uses derivative instruments, typically fixed-rate swaps, costless collars, puts, calls and basis differential swaps, to manage commodity price risk associated with a portion of its forecasted oil and gas production. Derivative instruments are recognized at their balance sheet date fair value as assets or liabilities in the consolidated balance sheets. Although the derivative instruments provide an economic hedge of the Company s exposure to commodity price risk associated with a portion of its forecasted oil and gas production, because the Company elected not to meet the criteria to qualify its derivative instruments for hedge accounting treatment, unrealized gains and losses as a result of changes in the fair value of derivative instruments are recognized as gain (loss) on derivative instruments, net in the consolidated statements of operations. Realized gains and losses as a result of cash settlements with counterparties to the Company s derivative instruments are also recorded as gain (loss) on derivative instruments, net in the consolidated statements of operations. The Company offsets fair value amounts recognized for derivative instruments executed with the same counterparty and subject to master netting agreements.

The Company s Board of Directors establishes risk management policies and reviews derivative instruments, including volumes, types of instruments and counterparties, on a quarterly basis. These policies require that derivative instruments be executed only by the President or Chief Financial Officer after consultation with and concurrence by the President, Chief Financial Officer and Chairman of the Board. The master contracts with approved counterparties identify the President and Chief Financial Officer as the only Company representatives authorized to execute trades. See Note 11. Derivative Instruments for further discussion of the Company s derivative instruments.

Stock-Based Compensation

The Company grants stock options, stock appreciation rights (SARs) that may be settled in cash or common stock at the option of the Company (Stock SARs), SARs that may only be settled in cash (Cash SARs), restricted stock awards and restricted stock units to directors, employees and independent contractors. The Company recognized the following stock-based compensation expense for the periods indicated which is reflected as general and administrative expense in the consolidated statements of operations:

	Years Ended December 31,		
	2011	2010	2009
		(In thousands)	
Stock Options and SARs	$ 1,546	$ 6,649	$ 1,192
Restricted Stock Awards and Units	13,965	9,959	10,105
	15,511	16,608	11,297
Less: amounts capitalized	(3,647)		
Total Stock-Based Compensation Expense	$ 11,864	$ 16,608	$ 11,297
Income Tax Benefit	$ 4,342	$ 6,152	$ 4,113

Stock Options and SARs. For stock options and Stock SARs that the Company expects to settle in common stock, stock-based compensation expense is based on the grant-date fair value and recognized over the vesting period (generally three years). For Cash SARs and any Stock SARs that the Company expects to settle in cash, stock-based compensation expense is based on the fair value remeasured at each reporting period, recognized over the vesting period (generally three years) and classified as other accrued liabilities for the portion of the awards that are vested or are expected to vest within the next 12 months, with the remainder classified as other long-term liabilities. Subsequent to vesting, the liability for any SARs that the Company expects to settle in cash is remeasured in earnings at each reporting period based fair value until the awards are settled. The Company recognizes stock-based compensation expense over the vesting period for stock options and SARs using the straight-line method, except for awards with performance conditions, in which case the Company uses the graded vesting method. Stock options typically expire ten years after the date of grant. SARs typically expire between four and seven years after the date of grant.

The Company uses the Black-Scholes-Merton option pricing model to compute the fair value of stock options and SARs, which requires the Company to make the following assumptions:

The risk-free interest rate is based on the zero-coupon United States Treasury yield for the expected term at date of grant.

The dividend yield on the Company s common stock is assumed to be zero since the Company does not pay dividends and has no current plans to do so in the future.

The volatility of the Company s common stock is based on daily, historical volatility of the market price of the Company s common stock over a period of time equal to the expected term and ending on the grant date.

The expected term is based on historical exercises for various groups of directors, employees and independent contractors.
Restricted Stock Awards and Units. For restricted stock awards and units, stock-based compensation expense is based on the grant-date fair value and recognized over the vesting period (generally one to three years) using the straight-line method, except for award or units with performance conditions, in which case the Company uses the graded vesting method. The fair value of restricted stock awards and units is based on the price of the Company s common stock on the grant date. For restricted stock awards and units granted to independent contractors, stock-based compensation expense is based on fair value remeasured at each reporting period and recognized over the vesting period (generally three years) using the straight-line method.

Foreign Currency

The U.S. dollar is the functional currency for the Company s operations in the U.K. North Sea. Transaction gains or losses that occur due to the realization of assets and the settlement of liabilities denominated in a currency other than the functional currency are recorded as other income, net in the consolidated statements of operations.

Income Taxes

Deferred income taxes are recognized at each reporting period for the future tax consequences of differences between the tax bases of assets and liabilities and their financial reporting amounts based on tax laws and statutory tax rates applicable to the periods in which the differences are expected to affect taxable income. The Company routinely assesses the realizability of its deferred tax assets and considers its estimate of future taxable income based on production of proved reserves at estimated future pricing in making such assessments by taxing jurisdiction. If the Company concludes that it is more likely than not that some portion or all of the deferred tax assets will not be realized, the deferred tax assets are reduced by a valuation allowance. The Company classifies interest and penalties associated with income taxes as interest expense.

Net Income (Loss) Per Common Share

Supplemental net income (loss) per common share information is provided below:

	Year Ended December 31,		
	2011	**2010**	**2009**
	(In thousands, except per share amounts)		
Net income (loss)	$ 36,629	$ 9,950	$ (204,845)
Basic weighted average common shares outstanding	39,077	33,861	31,006
Effect of dilutive instruments	591	444	
Diluted weighted average shares outstanding	39,668	34,305	31,006
Net income (loss) per share			
Basic	$ 0.94	$ 0.29	$ (6.61)
Diluted	$ 0.92	$ 0.29	$ (6.61)

Basic net income (loss) per common share is based on the weighted average number of shares of common stock outstanding during the period. Diluted net income (loss) per common share is based on the weighted average number of common shares and all potentially dilutive common shares outstanding during the period which include restricted stock awards and units, stock options, Stock SARs expected to be settled in common stock, warrants and convertible debt. The Company excluded 4,202 and 23,668 shares related to restricted stock awards and units, and stock options from the calculation of dilutive shares for the years ended December 31, 2011 and 2010, respectively, because the grant prices were greater than the average market prices of the common shares for the period and would be antidilutive to the computation. The Company excluded 1,205,770 shares related to stock options from the calculation of dilutive shares for the year ended December 31, 2009 due to the net loss reported in that period. Shares of common stock subject to issuance upon the conversion of the Convertible Senior Notes did not have an effect on the calculation of dilutive shares for the years ended December 31, 2011, 2010 or 2009 because the conversion price was in excess of the market price of the common stock for those periods.

Supplemental Cash Flow Information

The consolidated statement of cash flows for the year ended December 31, 2009 does not include the non-cash fair value adjustments to the carrying amount of the Company s investment in Pinnacle Gas Resources, Inc. recognized in other comprehensive income of $0.1 million, net of income taxes.

Recently Adopted Accounting Pronouncements

In January 2010, the FASB issued Accounting Standards Update No. 2010-03 to align the oil and gas reserve estimation and disclosure requirements of Topic 932 (Extractive Industries Oil and Gas) with the requirements of Securities and Exchange Commission (SEC) Release 33-8994. This release is effective for financial statements issued on or after January 1, 2010. The Company adopted this guidance effective December 31, 2009. This release changes the accounting and disclosure requirements of oil and gas reserves and is intended to modernize and update the oil and gas disclosure requirements, to align them with current industry practices and to adapt to changes in technology. The new rules permit the use of new technologies to determine proved reserves, allow companies to disclose their probable and possible reserves and allow proved undeveloped reserves to be maintained beyond a five-year period only if justified by specific circumstances. The new rules require companies to report the independence and qualification of the person primarily responsible for the preparation or audit of its reserve estimates, and to file reports when a third party is relied upon to prepare or audit its reserve estimates. The new rules also require that the net present value of oil and gas reserves reported and used in the full cost ceiling test calculation be based upon average market prices for sales of oil and gas on the first calendar day of each month during the preceding 12-month period prior to the end of the current reporting period.

3. INVESTMENTS

Investments consisted of the following at December 31, 2011 and 2010:

	December 31, 2011	December 31, 2010
	(In thousands)	
Pinnacle Gas Resources, Inc.	$	$ 869
Oxane Materials, Inc.	2,523	2,523
	$ 2,523	$ 3,392

Oxane Materials, Inc.

In May 2008, the Company entered into a strategic alliance agreement with Oxane in connection with the development of a proppant product to be used in the Company s exploration and production program. The Company contributed approximately $2.0 million to Oxane in exchange for warrants to purchase Oxane common stock and for certain exclusive use and preferential purchase rights with respect to the proppant. The Company simultaneously invested an additional $500,000 in a convertible promissory note from Oxane. The convertible promissory note accrued interest at a rate of 6% per annum. During the fourth quarter of 2008, the Company converted the promissory note into 630,371 shares of Oxane preferred stock.

Pinnacle Gas Resources, Inc.

In 2003, the Company contributed its interests in certain oil and gas leases in Wyoming and Montana in areas prospective for coalbed methane to a newly formed entity, Pinnacle.

At March 31, 2009, the market value of the Company s investment in Pinnacle had consistently remained below its book value since October 2008. The Company determined that the impairment was other than temporary, and accordingly, recognized an impairment of $2.1 million at March 31, 2009. At December 31, 2010, the Company reported the fair value of its investment in Pinnacle at $0.9 million (based on the closing price of Pinnacle s common stock on December 31, 2010).

On January 25, 2011, Pinnacle announced that it had been acquired by Powder Holdings, LLC, an entity controlled by SW Energy Capital LP. Under the terms of the merger agreement, the Company received $0.9 million, or $0.34 per share, for its 2,555,825 shares of Pinnacle common stock during the second quarter of 2011.

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4. PROPERTY AND EQUIPMENT, NET

At December 31, 2011 and 2010, property and equipment, net consisted of the following:

	December 31, 2011	December 31, 2010
	(In thousands)	
Proved oil and gas properties	$ 1,305,084	$ 941,267
Accumulated depreciation, depletion and amortization	(397,737)	(314,602)
Proved oil and gas properties, net	907,347	626,665
Costs not subject to amortization		
Unevaluated leasehold and seismic costs	277,425	258,139
Capitalized interest	46,471	38,782
Exploratory wells in progress	70,533	55,558
Total costs not subject to amortization	394,429	352,479
Other property and equipment	12,835	7,314
Accumulated depreciation	(4,097)	(3,401)
Other property and equipment, net	8,738	3,913
Total property and equipment, net	$ 1,310,514	$ 983,057

Costs not subject to amortization totaling $394.4 million at December 31, 2011 were incurred in the following periods: $204.4 million in 2011, $113.9 million in 2010, $25.0 million in 2009 and $51.1 million in 2008 and prior years.

Impairments of oil and gas properties

In June 2010, the Company concluded that it was uneconomical to pursue development on the license covering the Monterey field in the U.K. North Sea and terminated further development efforts. Because the U.K. cost center had no proved reserves at that time, the $2.7 million ($1.7 million net of income taxes) of costs associated with the license covering the Monterey field resulted in an impairment for the year ended December 31, 2010.

The net capitalized costs of the Company s U.S. oil and gas properties exceeded the cost center ceiling at March 31, 2009 resulting in an impairment of $216.4 million ($140.6 million net of income taxes) and at December 31, 2009, resulting in an impairment of $122.5 million ($78.1 million net of income taxes). To measure the cost ceiling for the first quarter of 2009, the Company elected to use a pricing date subsequent to the balance sheet date, as allowed by the accounting requirements in effect at the time. Had the Company used prices in effect as of March 31, 2009, the Company would have recognized an impairment of $323.2 million ($206.1 million net of tax) for the first quarter of 2009. The option to use a pricing date subsequent to the balance sheet date is no longer available under the oil and gas reserve estimation and disclosure requirements which the Company adopted effective December 31, 2009.

Decreases in oil and/or gas prices as well as changes in production rates, levels of reserves, evaluation of costs not subject to amortization, future development and production costs could result in future impairments of oil and gas properties.

Sale of Non-Core Area Barnett Shale Properties

In May 2011, the Company sold a substantial portion of its non-core area Barnett Shale properties to KKR Natural Resources (KKR), a partnership formed between an affiliate of Kohlberg Kravis Roberts & Co. L.P. and Premier Natural Resources. Net proceeds received from the sale were approximately $98.0 million, which represent an agreed upon purchase price of approximately $104.0 million less net purchase price adjustments. Purchase price adjustments primarily relate to proceeds received by the Company for sales of hydrocarbons from such properties between the effective date of January 1, 2011 and the closing date of May 17, 2011. The proceeds from such sale were recognized as a reduction of proved oil and gas properties, net.

Marcellus Shale Joint Venture

As discussed further in Note 10. Related Party Transactions, in September 2010, the Company completed the sale of 20% of its interests in substantially all of its oil and gas properties in Pennsylvania that had been subject to the Avista joint venture to Reliance for $13.1 million in cash and a commitment by Reliance to pay 75% of certain of the Company s future development costs up to approximately $52.0 million. The proceeds were recognized as a reduction of proved oil and gas properties, net and 20% of the unevaluated leasehold and seismic costs associated with these properties (approximately $16.0 million) was also transferred to proved oil and gas properties, net.

During the third and fourth quarters of 2010 and the second quarter of 2011, ACP II declared and paid cash distributions to affiliates of Avista. Because these distributions exceeded Avista sinternal rates-of-return and return-on-investment thresholds, the Company received cash distributions of approximately $38.8 million during the third and fourth quarters of 2010 and $3.3 million in the second quarter of 2011on its B Units, which were recognized as reductions of capitalized oil and gas property costs.

In June 2011, in accordance with the title and post-closing adjustment provisions of the purchase and sale agreements of the sale described above, the Company provided additional interests in oil and gas properties in parts of Pennsylvania in the Marcellus Shale to Reliance in substitution of properties included in the sale that were affected by certain alleged title defects. In exchange for such substitute properties, the Company received $0.3 million in cash from Reliance relating to the sale of 20% of its interest.

Eagle Ford Joint Venture

On September 28, 2011, the Company completed the sale of 20% of its interests in oil and gas properties in parts of the Eagle Ford Shale to GAIL GLOBAL (USA) INC. (GAIL), a wholly-owned subsidiary of GAIL (India) Limited, effective September 1, 2011. Under the purchase and participation agreement for this transaction, the Company received $63.7 million in cash which was recognized as a reduction of proved oil and gas properties. As part of the consideration for the purchase, GAIL committed to pay a development carry of 50% of certain of the Company s future development costs up to approximately $31.3 million, as further described below. The Eagle Ford Shale assets to be conveyed to GAIL under the terms of the agreement include approximately 4,040 net acres located primarily in LaSalle County, Texas and a 20% interest in eight completed horizontal wells. The agreement also provides for an ongoing joint venture between the Company and GAIL with respect to the interests being purchased by GAIL. The development carry obligation extends until June 30, 2013 or until the earlier full utilization of the approximately $31.3 million development carry, subject to certain conditions and extensions. The Company will continue to operate the joint venture properties that it currently operates, and currently expects the approximately $31.3 million development carry to be exhausted in the first quarter of 2012. The joint venture provides for an area of mutual interest including the purchased interests and specified areas adjacent to such interests. GAIL will have the right to purchase certain interests acquired by the Company in the area of mutual interest at a specified premium to the price paid by the Company.

5. INCOME TAXES

The components of income tax (expense) benefit were as follows:

	Year Ended December 31, 2011	2010 (In thousands)	2009
Current income tax expense			
U.S. Federal	$ (404)	$	$ (6)
State	(661)	(4,236)	(65)
U.K.			
Total current income tax expense	(1,065)	(4,236)	(71)
Deferred income tax (expense) benefit			
U.S. Federal	(22,100)	(4,937)	111,325
State	(1,292)	3,444	2,053
U.K.	6,237		
Total deferred income tax (expense) benefit	(17,155)	(1,493)	113,378
Total income tax (expense) benefit	$ (18,220)	$ (5,729)	$ 113,307

The Company s income tax (expense) benefit differs from the income tax (expense) benefit computed by applying the U.S. federal statutory corporate income tax rate of 35% to income (loss) before income taxes as follows:

	Year Ended December 31, 2011	2010 (In thousands)	2009
Income (loss) before income taxes			
U.S.	$ 58,004	$ 15,679	$ (318,152)
U.K.	(3,155)		
Total income (loss) before income taxes	$ 54,849	$ 15,679	$ (318,152)
Income tax (expense) benefit at the statutory rate	$ (19,197)	$ (5,488)	$ 111,353
State income taxes, net of U.S. federal income tax benefit	(1,722)	(792)	2,270
U.K. income tax benefit	2,240		
Adjustment to prior period state income tax provision	(4,735)		
Benefit of prior period U.K. net operating losses	3,997		
Previously unbenefitted capital loss associated with investment in Pinnacle	1,171		
Nondeductible expenses	26	(46)	(35)
Other		597	(281)
Total income tax (expense) benefit	$ (18,220)	$ (5,729)	$ 113,307

Deferred income taxes reflect the impact of temporary differences between the amount of assets and liabilities recognized for financial reporting purposes and such amounts recognized for tax purposes. At December 31, 2011 and 2010, deferred tax assets and liabilities are comprised of the following:

	December 31, 2011	December 31, 2010
	(In thousands)	
Deferred income tax assets		
Net operating loss carryforward - U.S.	$ 42,442	$ 52,683
Net operating loss carryforward - U.K.	49,431	
Property and equipment - U.S.	55,307	57,201
Stock-based compensation	4,469	4,855
Allowance for doubtful accounts	806	915
Fair value of derivatives	75	
Valuation allowance	(681)	
Investment in Pinnacle		1,135
Other	1,335	590
	153,184	117,379
Deferred income tax liabilities		
Unamortized discount on Convertible Senior Notes	(1,329)	(2,372)
Property and equipment - U.K.	(43,193)	
Capitalized interest	(45,469)	(38,812)
Fair value of derivatives	(13,123)	(8,894)
	(103,114)	(50,078)
Net deferred income tax asset	$ 50,070	$ 67,301

Deferred income tax assets and liabilities are classified as current or long term consistent with the classification of the related temporary difference, separately by tax jurisdiction. At December 31, 2011 and 2010, the net deferred income tax asset is classified as follows:

	December 31, 2011	December 31, 2010
	(In thousands)	
Noncurrent deferred income tax asset	$ 59,755	$ 72,587
Current deferred income tax liability	(9,685)	(5,286)
Net deferred income tax asset	$ 50,070	$ 67,301

As of December 31, 2011, the Company had U.S. income tax net operating loss (NOL) carryforwards of approximately $147.5 million which expire between 2019 and 2031 if not utilized in earlier periods. The realization of the deferred tax assets related to the U.S. NOL carryforwards is dependent on the Company s ability to generate sufficient future taxable income in the U.S. within the applicable carryforward periods. As of December 31, 2011, the Company determined it was more likely than not that some of its state NOL carryforwards would not be realized and accordingly, established a valuation allowance totaling $0.7 million. The Company believes it will be able to generate sufficient future taxable income in the U.S. within the carryforward periods. As such, the Company believes that it is more likely than not that its net deferred income tax assets will be fully realized.

The ability of the Company to utilize its U.S. NOL carryforwards to reduce future taxable income is subject to various limitations under the Internal Revenue Code of 1986, as amended (the Code). The utilization of such carryforwards may be limited upon the occurrence of certain ownership changes, including the purchase or sale of stock by 5% shareholders and the offering of stock by the Company during any three-year period resulting in an aggregate change of more than 50% in the beneficial ownership of the Company. In the event of an ownership change, Section 382 of the Code imposes an annual limitation on the amount of a Company s taxable income that can be offset by these carryforwards.

The limitation is generally equal to the product of (a) the fair market value of the equity of the Company multiplied by (b) a percentage approximately equivalent to the yield on long-term tax exempt bonds during the month in which an ownership change occurs. In addition, the limitation is increased if there are recognized built-in gains during any post-change year, but only to the extent of any net unrealized built-in gains inherent in the assets sold. As of December 31, 2011, the Company believes an ownership change occurred in February 2005 with an annual limitation of $12.6 million. Because the Company s pre-change NOL is $9.8 million, the Company does not believe it has a Section 382 limitation on the ability to utilize its U.S. NOL as of December 31, 2011. Future equity transactions involving the Company or 5% shareholders of the Company (including, potentially, relatively small transactions and transactions beyond the Company s control) could cause further ownership changes and therefore a limitation on the annual utilization of the U.S. NOL carryforwards.

The Company receives a tax deduction during the period stock options are exercised, generally for the excess of the exercise date stock price over the exercise price of the option. The Company also receives a tax deduction during the period restricted stock awards and units vest, generally equal to the fair value on the date that the awards or units vest. Because these stock-based compensation tax deductions did not reduce current taxes payable as a result of U.S. NOL carryforwards, the benefit of these tax deductions has not been reflected in the U.S. NOL carryforward deferred tax asset. Stock-based compensation deductions included in the U.S. NOL carryforwards of $147.5 million but not reflected in deferred tax assets were $29.2 million at December 31, 2011. The Company plans to recognize the $10.2 million deferred tax asset associated with these stock-based compensation tax deductions when all other components of the U.S. NOL carryforward deferred tax asset have been fully utilized. If and when the stock-based compensation deduction related U.S. NOL carryforward deferred tax asset is realized, the tax benefit of reducing current taxes payable will be credited directly to additional paid-in capital.

At December 31, 2011, the Company had no material uncertain tax positions and the tax years since 1999 remain open to review by federal and various state tax jurisdictions.

6. DEBT

At December 31, 2011 and 2010, debt consisted of the following:

	December 31,	
	2011	2010
	(In thousands)	
Senior Notes	$ 600,000	$ 400,000
Unamortized discount for Senior Notes	(5,464)	(2,751)
Convertible Senior Notes	73,750	73,750
Unamortized discount for Convertible Senior Notes	(3,799)	(6,405)
Senior Secured Revolving Credit Facility	47,000	93,500
Senior Secured Multicurrency Credit Facility	17,813	
Other		160
	729,300	558,254
Less: Current maturities		(160)
	$ 729,300	$ 558,094

Senior Notes

On November 2, 2010, the Company issued $400.0 million aggregate principal amount of 8.625% Senior Notes due 2018 (Senior Notes) at a price to the initial purchasers of 99.302% of the principal amount in a private placement. The net proceeds of $387.5 million (after deducting the initial purchasers discount and the Company s expenses) were used to repay in full borrowings outstanding under the Prior Credit Facility (defined below) and to fund in part the tender offer for $300.0 million of the Convertible Senior Notes as described below.

On November 17, 2011, the Company issued an additional $200.0 million aggregate principal amount of 8.625% Senior Notes due 2018 at a price to the initial purchasers of 98.501% of the principal amount in a private placement. The net proceeds of $194.5 million (after deducting the initial purchasers discount and the Company s expenses) were used to repay a substantial portion of the borrowings outstanding under the Revolving Credit Facility (defined below). These notes were issued as additional notes under the indenture governing the Senior Notes and pursuant to which the Company had previously issued $400.0 million aggregate principal amount of Senior Notes in November 2010, and under the indenture are treated as a single series with substantially identical terms as the Senior Notes previously issued in November 2010. The Senior Notes are guaranteed by certain of the Company s subsidiaries: Bandelier Pipeline Holding, LLC; CLLR, Inc.; Carrizo (Eagle Ford) LLC; Carrizo (Marcellus) LLC; Carrizo (Marcellus) WV LLC; Carrizo Marcellus Holding, Inc.; Carrizo (Niobrara) LLC; Hondo Pipeline, Inc.; and Mescalero Pipeline, LLC.

The Senior Notes bear interest at 8.625% per annum which is payable semi-annually on each October 15 and April 15. The Senior Notes mature on October 15, 2018 with interest payable semi-annually. At any time prior to October 15, 2013, the Company may, subject to certain conditions, on one or more occasions, redeem up to 35% of the aggregate principal amount of Senior Notes at a redemption price of 108.625%, of the principal amount, plus accrued and unpaid interest, if any, using the net cash proceeds of one or more equity offerings by the Company. Prior to October 15, 2014, the Company may redeem all or part of the Senior Notes at 100% of the principal amount thereof, plus accrued and unpaid interest and a make whole premium. On and after October 15, 2014, the Company may redeem all or a part of the Senior Notes, at redemption prices decreasing from 104.313% of the principal amount to 100% of the principal amount on October 15, 2017, plus accrued and unpaid interest. If a Change of Control (as defined in the indenture governing the Senior Notes) occurs, the Company may be required by holders to repurchase Senior Notes for cash at a price equal to 101% of the aggregate principal amount, plus any accrued but unpaid interest.

The indenture governing the Senior Notes contains covenants that, among other things, limit the Company s ability and the ability of its restricted subsidiaries to: pay distributions on, purchase or redeem the Company s common stock or other capital stock or redeem subordinated debt; make investments; incur or guarantee additional indebtedness or issue certain types of equity securities; create certain liens; sell assets; consolidate, merge or transfer all or substantially all of the Company s assets; enter into agreements that restrict distributions or other payments from the Company s restricted subsidiaries to the Company; engage in transactions with affiliates; and create unrestricted subsidiaries.

The Senior Notes are subject to customary events of default, including those relating to failures to comply with the terms of the indenture governing the Senior Notes, certain failures to file reports with the SEC, certain cross defaults of other indebtedness and mortgages and certain failures to pay final judgments.

In June 2011 and February 2012, the Company completed the exchange of registered 8.625% Senior Notes due 2018 for any and all of its unregistered $400.0 million and $200.0 million aggregate principal amount of 8.625% Senior Notes due 2018, respectively.

Convertible Senior Notes

In May 2008, the Company issued $373.8 million aggregate principal amount of 4.375% convertible senior notes due 2028 (the Convertible Senior Notes). Interest is payable on June 1 and December 1 each year. The notes are convertible, using a net share settlement process, into a combination of cash and Company common stock that entitles holders of the Convertible Senior Notes to receive cash up to the principal amount ($1,000 per note) and common stock in respect of the remainder, if any, of the Company s conversion obligation in excess of such principal amount.

In November 2010, the Company completed a tender offer for $300.0 million aggregate principal amount outstanding of the Convertible Senior Notes for an aggregate consideration of approximately $306.3 million, including accrued and unpaid interest on the Convertible Senior Notes. Each holder received $1,000 for each $1,000 principal amount of Convertible Senior Notes purchased in the tender offer, plus accrued and unpaid interest. The Company recognized a $31.0 million pre-tax loss on extinguishment of debt as a result of the purchase of the Convertible Senior Notes in the tender offer, substantially all of which was non-cash representing the associated unamortized discount and deferred financing costs. After the Company s purchase of $300.0 million aggregate principal amount of Convertible Senior Notes, $73.8 million aggregate principal amount of Convertible Senior Notes was outstanding as of December 31, 2011 and December 31, 2010.

The notes are convertible into the Company s common stock at a ratio of 9.9936 shares per $1,000 principal amount of notes, equivalent to a conversion price of approximately $100.06. This conversion rate is subject to adjustment upon certain corporate events. In addition, if certain fundamental changes occur on or before June 1, 2013, the Company will in some cases increase the conversion rate for a holder electing to convert notes in connection with such fundamental change; provided, that in no event will the total number of shares issuable upon conversion of a note exceed 14.7406 per $1,000 principal amount of notes (subject to adjustment in the same manner as the conversion rate).

Holders may convert the notes only under the following conditions: (a) during any calendar quarter if the last reported sale price of the Company s common stock exceeds 130 percent of the conversion price for at least 20 trading days in a period of 30 consecutive trading days ending on the last trading day of the immediately preceding calendar quarter, (b) during the five business days after any five consecutive trading day period in which the trading price per $1,000 principal amount of the notes is equal to or less than 97% of the conversion value of such notes, (c) during specified periods if specified distributions to holders of the Company s common stock are made or specified corporate transactions occur, (d) prior to the close of business on the business day preceding the redemption date if the notes are called for redemption or (e) on or after March 31, 2028 and prior to the close of business on the business day prior to the maturity date of June 1, 2028.

The holders of the Convertible Senior Notes may require the Company to repurchase the notes on June 1, 2013, 2018 and 2023, or upon a fundamental corporate change at a repurchase price in cash equal to 100 percent of the principal amount of the notes to be repurchased plus accrued and unpaid interest, if any. The Company may redeem notes at any time on or after June 1, 2013 at a redemption price equal to 100 percent of the principal amount of the notes to be redeemed plus accrued and unpaid interest, if any.

The Convertible Senior Notes are subject to customary non-financial covenants and events of default, including certain cross defaults of other indebtedness and mortgages, the occurrence and continuation of which could result in the acceleration of amounts due under the Convertible Senior Notes.

The Convertible Senior Notes are unsecured obligations of the Company and rank equal to the Senior Notes and all future senior unsecured debt of the Company but rank second in priority to the Revolving Credit Facility.

On November 2, 2010, in connection with the issuance of the Senior Notes, the Company and the guarantors of the Senior Notes entered into a supplement to the indenture governing the Convertible Senior Notes. Pursuant to this supplemental indenture, the guarantors of the Senior Notes also became guarantors of the Convertible Senior Notes. The guarantee of the Convertible Senior Notes was required under the indenture governing the Convertible Senior Notes as a result of the issuance of the guarantees of the Senior Notes.

The Company valued the Convertible Senior Notes at May 21, 2008, as $309.6 million of debt and $64.2 million of equity representing the fair value of the conversion premium. The resulting debt discount is being amortized to interest expense through June 1, 2013, the first date on which the holders may require the Company to repurchase the Convertible Senior Notes, resulting in an effective interest rate of approximately 8% for the Convertible Senior Notes. Approximately $27.1 million of the remaining debt discount associated with the Convertible Senior Notes purchased in the tender offer discussed above was recognized as a component of the loss on the extinguishment of debt. Amortization of the debt discount amounted to $2.6 million, $11.6 million and $12.1 million for the years ended December 31, 2011, 2010 and 2009, respectively.

Senior Secured Revolving Credit Facility

On January 27, 2011, the Company entered into a new $750.0 million senior secured revolving credit facility with a five-year term (Revolving Credit Facility) with BNP Paribas as the administrative agent, sole book runner and lead arranger. The Revolving Credit Facility permits the Company to borrow up to the lesser of (i) the borrowing base (as defined in the senior credit agreement governing the Revolving Credit Facility) and (ii) $750.0 million. The Revolving Credit Facility matures on January 27, 2016. It is secured by substantially all of the Company s assets (excluding the Company s Carrizo U.K. assets as described below under U.K Huntington Field Development Project Credit Facility and the Company s Utica Shale assets) and is guaranteed by certain of the Company s domestic subsidiaries: Bandelier Pipeline Holding, LLC, Carrizo (Eagle Ford) LLC, Carrizo Marcellus Holding Inc., Carrizo (Marcellus) LLC, Carrizo (Marcellus) WV LLC, Carrizo (Niobrara) LLC, CLLR, Inc., Hondo Pipeline, Inc. and Mescalero Pipeline, LLC. Any subsidiary of the Company that does not currently guarantee the Company s obligation under the Revolving Credit Facility that subsequently becomes a material domestic subsidiary (as defined under the credit agreement governing the Revolving Credit Facility) will be required to guarantee the Company s obligations under the Revolving Credit Facility.

The initial borrowing base under the Revolving Credit Facility was $350.0 million and the current borrowing base is $340.0 million. The borrowing base will be redetermined by the lenders at least semi-annually on each May 1 and November 1, with the next redetermination expected as of May 1, 2012. The Company and the lenders may each request one unscheduled borrowing base redetermination between each scheduled redetermination. The borrowing base will also be reduced in certain circumstances as a result of certain issuances of senior notes, cancellation of certain hedging positions and as a result of certain asset sales. The amount the Company is able to borrow with respect to the borrowing base is subject to compliance with the financial covenants and other provisions of the credit agreement governing the Revolving Credit Facility. Subsequent to the sale of the Company s non-core area

Barnett Shale properties in the second quarter of 2011 described in Note 4. Property and Equipment, net, the borrowing base availability under the Revolving Credit Facility was reduced from $350.0 million to $300.0 million. On June 10, 2011, the borrowing base availability was raised to $340.0 million after completing the regular semi-annual borrowing base redetermination. The borrowing base availability remained at $340.0 million after completing the regular semi-annual borrowing base redetermination on December 5, 2011.

If the outstanding principal balance of the revolving loans and the aggregate face amount of all letters of credit under the Revolving Credit Facility exceeds the borrowing base at any time as a result of a redetermination of the borrowing base, the Company has the option within 30 days to take any of the following actions, either individually or in combination: make a lump sum payment curing the deficiency, deliver reserve engineering reports and mortgages covering additional oil and gas properties sufficient in the lenders opinion to increase the borrowing base and cure the deficiency or begin making equal monthly principal payments that will cure the deficiency within the next six-month period. Upon certain adjustments to the borrowing base, the Company is required to make a lump sum payment in an amount equal to the amount by which the outstanding principal balance of the revolving loans and the aggregate face amount of all letters of credit under the Revolving Credit Facility exceeds the borrowing base. Otherwise, any unpaid principal will be due at maturity.

The annual interest rate on each base rate borrowing is (a) the greatest of the Agent s Prime Rate, the Federal Funds Effective Rate plus 0.5% and the adjusted LIBO rate for a three-month interest period on such day plus 1.00%, plus (b) a margin between 1.00% and 2.00% (depending on the then-current level of borrowing base usage). The interest rate on each Eurodollar loan will be the adjusted LIBO rate for the applicable interest period plus a margin between 2.00% to 3.00% (depending on the then-current level of borrowing base usage).

The Company is subject to certain covenants under the terms of the Revolving Credit Facility which include, but are not limited to, the maintenance of the following financial covenants: (i) a Total Debt to EBITDA (each as defined in the credit agreement governing the Revolving Credit Facility) ratio of not more than (a) 4.75. to 1.00 for fiscal quarter ending December 31, 2011, (b) 4.25 to 1.00 for fiscal quarters ending March 31, 2012 through June 30, 2012 and (c) 4.00 to 1.00 for fiscal quarters ending September 30, 2012 and thereafter; (ii) a current ratio of not less than 1.0 to 1.0; (iii) a Senior Debt (as defined in the credit agreement governing the Revolving Credit Facility) to EBITDA ratio of not more than 2.50 to 1.00; and (iv) an EBITDA to Interest Expense (as defined in the credit agreement governing the Revolving Credit Facility) ratio of not less than 2.50 to 1.00. At December 31, 2011, the Total Debt to EBITDA ratio was 3.99 to 1.00, the current ratio was 1.55 to 1.0, the Senior Debt to EBITDA ratio was 0.08 to 1.00 and the EBITDA to Interest Expense ratio was 4.35 to 1.00. Because the calculation of the financial ratios are made as of a certain date, the financial ratios can fluctuate significantly period to period as the amounts outstanding under the Revolving Credit Facility are dependent on the timing of cash flows related to operations, capital expenditures, sales of oil and gas properties and securities offerings.

The Revolving Credit Facility also places restrictions on the Company and certain of its subsidiaries with respect to additional indebtedness, liens, dividends and other payments to shareholders, repurchases or redemptions of the Company s common stock, redemptions of Senior Notes, investments, acquisitions, mergers, asset dispositions, transactions with affiliates, hedging transactions and other matters.

The Revolving Credit Facility is subject to customary events of default, including a change in control (as defined in the credit agreement governing the Revolving Credit Facility). If an event of default occurs and is continuing, the Majority Lenders (as defined in the credit agreement governing the Revolving Credit Facility) may accelerate amounts due under the Revolving Credit Facility (except for a bankruptcy event of default, in which case such amounts will automatically become due and payable).

On January 27, 2011, the Company borrowed $112.0 million under the Revolving Credit Facility, which was used to repay in full indebtedness outstanding under the Prior Credit Facility (as defined and described below), to pay transaction costs associated with the entrance into the Revolving Credit Facility and for other general corporate purposes.

At December 31, 2011, the Company had $47.0 million of borrowings outstanding under the Revolving Credit Facility with a weighted average interest rate of 3.03%. At December 31, 2011, the Company also had $0.4 million in letters of credit outstanding which reduced the amounts available under the Revolving Credit Facility. The Revolving Credit Facility is generally used to fund ongoing working capital needs and the remainder of the Company s capital expenditure plan to the extent such amounts exceed the cash flow from operations, proceeds from the sale of oil and gas properties and securities offerings.

Prior Senior Secured Revolving Credit Facility

Prior to January 27, 2011, the Company had a senior secured revolving credit facility (the Prior Credit Facility) with Wells Fargo Bank, N.A., as administrative agent. In connection with the Company s entrance into the Revolving Credit Facility as discussed above, on January 27, 2011, the Company repaid its full indebtedness outstanding under the senior credit agreement governing the Prior Credit Facility and terminated such senior credit agreement. As a result, the Company recognized a $0.9 million non-cash pre-tax loss on extinguishment of debt, related to the deferred financing costs attributable to the commitments of two banks in the Prior Credit Facility who are not participating in the new credit facility.

U.K. Huntington Field Development Project Credit Facility

On January 28, 2011, the Company and Carrizo UK Huntington Ltd., a wholly-owned subsidiary of the Company incorporated in England and Wales (Carrizo UK), as Borrower, entered into a Senior Secured Multicurrency Credit Facility Agreement with BNP Paribas and Societe Generale, as lead arrangers and original lenders (the Huntington Facility). The Huntington Facility is secured by substantially all of Carrizo UK s assets and is limited recourse to the Company. The Huntington Facility provides financing for a substantial portion of Carrizo UK s share of costs associated with the Huntington Field development project in the U.K. North Sea. The Huntington Facility provides for a multicurrency credit facility consisting of (i) a term loan facility to be used to fund Carrizo UK s share of project development costs, (ii) a contingent cost overrun term loan facility and (iii) a post-completion revolving credit facility providing for loans and letters of credit to be used to fund certain abandonment and decommissioning costs following project completion.

The total term loan facility commitment is $55.0 million, with availability under the facility subject to a borrowing base, which is currently in excess of the commitment. The total cost overrun facility commitment is $6.5 million, which may be utilized only when funds under the term loan facility have been exhausted and certain other requirements are satisfied. The total post-completion revolving credit facility commitment is $22.5 million. Availability under each of the term loan facility and the cost overrun facility is subject to borrowing bases that are generally based on consolidated cash flow and debt service projections for Carrizo UK attributable to certain proved reserves in the Huntington Field development project. The borrowing bases of the term loan facility and the cost overrun facility will be redetermined by the lenders at least semi-annually on each April 1 and October 1 in connection with the updating and recalculation of revenue and cash flow projections with respect to the Huntington Field development project. Based on the redetermination and recalculation, which occurred in the third quarter 2011, availability of the term loan facility and cost overrun facility is currently $55.0 million and $6.5 million, respectively. If the outstanding principal balance of the term loan facility and cost overrun facility exceeds the aggregate borrowing base for such facility at any time as a result of a redetermination of such facility s borrowing base, Carrizo UK will be obligated to make a payment to cure the deficiency within five business days.

Initial borrowings under the term loan facility and cost overrun facility were conditioned on, among other things, the Company s having made and spent an approximately $22.0 million equity contribution to Carrizo UK, which was completed in February 2011. Prior to project completion, the Company may be required under the Huntington Facility to make an additional equity contribution to Carrizo UK in the event the term loan borrowing base is reduced to a level at or above the amount of borrowings then outstanding. The Company may also be responsible under the Huntington Facility for making certain additional equity contributions to Carrizo UK in the event of certain specified projected Cost Overruns (as defined in the Huntington Facility). To the extent that the cost overrun facility and any required equity contributions are insufficient, the Company is responsible for funding any Cost Overruns on a 100% basis. If after project completion, the lenders reasonably determine that Carrizo UK is required to incur additional capital expenditures that were not contemplated by the Huntington Field development plan originally approved by the U.K. Department of Energy and Climate Change, the Company is responsible for funding such additional expenditures. The Company is responsible for making certain other payments under the Huntington Facility, including funding certain projected working capital shortfalls, providing cash collateral for letters of credit issued under the post-completion revolving credit facility and paying certain costs of the required hedging arrangements described below.

The annual interest rate on each borrowing is (a) LIBOR (EURIBOR for euro-denominated loans) for the applicable interest period, plus (b) a margin of (i) 3.50% until the completion of the Huntington Field development project and 3.0% thereafter for the term loan credit facility and post-completion revolving credit facility or (ii) 4.75% for the cost overrun facility. Borrowings under the term loan and cost overrun facilities are available until the earlier of December 31, 2012 or the achievement of certain project development milestones. The term loan and cost overrun facilities mature on December 31, 2014, subject to acceleration in the event that future projection estimates of remaining reserves in the project area have declined to less than 25% of the level initially projected by Carrizo UK and the lenders. Letters of credit under the post-completion revolving credit facility mature on December 31, 2016. Amounts outstanding under the term loan or cost overrun facility must be repaid according to the following schedule: (i) 45% will be due on December 31, 2012, (ii) 20% will be due on June 30, 2013, (iii) 20% will be due on December 31, 2013, (iv) 10% will be due on June 30, 2014 and (iv) the remaining 5% will be due on the final maturity date of December 31, 2014.

The Huntington Facility requires Carrizo UK to enter into certain hedging arrangements in order to hedge a specified portion of the Huntington Field development project s exposure to fluctuating petroleum prices. This obligation was satisfied in February 2011. In addition, Carrizo UK may, but is not required, to hedge its exposure to changes in interest rates or exchange rates, and permits Carrizo UK to enter into additional hedging arrangements. The Huntington Facility places restrictions on Carrizo UK with respect to additional indebtedness, liens, the extension of credit, dividends or other payments to the Company or its other subsidiaries, investments, acquisitions, mergers, asset dispositions, commodity transactions outside of the mandatory hedging program, transactions with affiliates and other matters.

The Huntington Facility is subject to customary events of default. If an event of default occurs and is continuing, the Majority Lenders (as defined in the Huntington Facility) may accelerate amounts due under the Huntington Facility.

As of December 31, 2011, borrowings outstanding under the Huntington Facility were £11.5 million, with a weighted average interest rate of 4.51% and no letters of credit had been issued. The British Pound denominated borrowings were translated to $17.8 million at December 31, 2011, resulting in an immaterial transaction gain recorded in Other income, net in the consolidated statements of operations.

7. ASSET RETIREMENT OBLIGATIONS

The following table sets forth asset retirement obligations for the years ended December 31, 2011 and 2010:

	Year Ended December 31, 2011	Year Ended December 31, 2010
	(In thousands)	
Asset retirement obligations at beginning of period	$ 6,369	$ 5,410
Liabilities incurred	3,772	181
Liabilities settled	(162)	(288)
Reduction due to property sales	(369)	
Accretion expense	311	216
Revisions of previous estimates	2,246	850
Asset retirement obligations due within one year*	(925)	
Asset retirement obligations at end of period	$ 11,242	$ 6,369

* *Classified as a current liability on the balance sheet, under the caption Other accrued liabilities*

The asset retirement obligations incurred for the year ended December 31, 2011 were primarily related to activity in the U.K. North Sea, Eagle Ford Shale, and Marcellus Shale. The revisions of previous estimates for the year ended December 31, 2011 related primarily to increases in estimates of abandonment costs of wells in the Marcellus Shale, Barnett Shale, and Gulf Coast region. The revisions of previous estimates for the year ended December 31, 2010 related primarily to increases in estimates of abandonment costs of wells in the Gulf Coast region.

8. COMMITMENTS AND CONTINGENCIES

From time to time, the Company is party to certain legal actions and claims arising in the ordinary course of business. While the outcome of these events cannot be predicted with certainty, management does not expect these matters to have a materially adverse effect on the financial position or results of operations of the Company.

The results of operations and financial position of the Company continue to be affected from time to time in varying degrees by domestic and foreign political developments as well as legislation and regulations pertaining to restrictions on oil and natural gas production, imports and exports, natural gas regulation, tax increases, environmental regulations and cancellation of contract rights. Both the likelihood and overall effect of such occurrences on the Company vary greatly and are not predictable.

Rent expense included in general and administrative expense for the years ended December 31, 2011, 2010 and 2009 was $1.7 million, $1.0 million, and $0.9 million, respectively, and includes rent expense primarily for the Company s corporate office and field offices.

At December 31, 2011, total minimum commitments from long-term non-cancelable operating leases, drilling rig, seismic and pipeline volume commitments are as follows:

	Amount (In thousands)
2012	$ 69,434
2013	57,917
2014	48,222
2015	22,241
2016	9,393
2017 and Thereafter	7,533
	$ 214,740

9. SHAREHOLDERS EQUITY AND STOCK INCENTIVE PLAN

Shareholders Equity

Common Stock. During the second and third quarters of 2011, the Company contributed $1.0 million and $1.1 million, respectively, in common stock of the Company to the University of Texas at Arlington, a university located within the area of our operations in the Barnett Shale. These contributions are included in general and administrative expense in the consolidated statements of operations.

In December 2010, the Company sold 3.975 million shares of its common stock in an underwritten public offering at a price to the underwriter of $28.90 per share. The Company used the net proceeds of approximately $114.9 million to repay a portion of the outstanding borrowings under the Prior Credit Facility.

In April 2010, the Company sold 3.22 million shares of its common stock in an underwritten public offering at a price to the underwriter of $23.00 per share. The Company used the net proceeds of approximately $73.8 million to repay a portion of the outstanding borrowings under the Prior Credit Facility.

Warrants. On November 24, 2009, the Company entered into a Land Agreement, as amended (the Land Agreement), with an unrelated third party and its affiliate. The Land Agreement expired by its terms on May 31, 2011. Under this arrangement, the Company was able to acquire up to $20.0 million of oil, gas and mineral interests/leases in certain specified areas in the Barnett Shale from such third party. In consideration of the Company s receipt of an option to purchase the leases acquired by the third party, each time the third party purchased a lease group under the Land Agreement the Company would issue to the third party s affiliate warrants to purchase shares of the Company s common stock with an exercise price of $22.09 and an expiration date of August 21, 2017. In addition, under certain circumstances where the Company reaches surface casing point on an initial well in one of the areas covered by the Land Agreement but has not achieved a specified lease up threshold for acreage in such area, the Company agreed to issue additional warrants. The warrants are subject to antidilution adjustments and may be exercised on a cashless basis.

Under the Land Agreement, the Company issued warrants to purchase 57,641 shares of common stock in 2010. During 2011 and January 2012, the Company issued additional warrants to purchase 28,576 and 6,983 shares, respectively of the Company s common stock to the third party s affiliate for leases acquired prior to the expiration of the Land Agreement.

Stock Incentive Plans

In 1997, the Company established the Incentive Plan of Carrizo Oil & Gas, Inc. (the Incentive Plan), which authorizes the granting of stock options, SARs that may be settled in cash or common stock at the option of the Company (Stock SARs), restricted stock awards and restricted stock units to directors, employees and independent contractors. The Company may grant awards of up to 4,395,000 shares under the Incentive Plan and through December 31, 2011, has issued stock options, restricted stock awards and restricted stock units covering 4,241,346 shares through December 31, 2011, net of forfeitures and excluding Stock SARs the Company has elected or expects to settle in cash.

Stock Options and Stock SARs. The table below summarizes the activity for stock options and Stock SARs the Company expects to settle in common stock for the three years ended December 31, 2011, 2010 and 2009:

	Shares	Weighted-Average Exercise Prices	Weighted-Average Remaining Life (In years)	Aggregate Intrinsic Value (In millions)
For the Year Ended December 31, 2009				
Oustanding, beginning of period	685,854	$ 4.71		
Granted	214,609	20.18		
Exercised	(5,000)	1.81		
Forfeited				
Oustanding, end of period	895,463	$ 8.43		
Exercisable, end of period	680,854	$ 4.73		
For the Year Ended December 31, 2010				
Oustanding, beginning of period	895,463	$ 8.43		
Granted				
Exercised	(266,433)	2.59		
Forfeited	(2,493)	18.56		
Other	(211,683)	20.22		
Oustanding, end of period	414,854	$ 6.10		
Exercisable, end of period	414,854	$ 6.10		
For the Year Ended December 31, 2011				
Oustanding, beginning of period	414,854	$ 6.10		
Granted				
Exercised	(151,500)	4.36		
Forfeited				
Oustanding, end of period	263,354	$ 7.11	1.82	$ 5.11
Exercisable, end of period	263,354	$ 7.11	1.82	$ 5.11

During 2009, the Company granted 211,683 Stock SARs which the Company then expected to settle in common stock. During July 2010, the Company elected to settle those Stock SARs in cash. Accordingly, during the third quarter of 2010, the Company recognized a fair value liability for the vested portion of the Stock SARs using assumptions in effect at the date the awards were modified and additional stock-based compensation expense of $0.3 million. The following table summarizes the weighted-average assumptions used in the Black-Scholes-Merton option pricing model to calculate the grant date and modification date fair values of the Stock SARs:

	2010	2009
Grant-date fair value	$	$ 10.14
Modification date fair value	$ 12.48	$
Volatility factor	60.7%	61.3%
Dividend yield		
Risk-free interest rate	1.1%	2.0%
Expected term (in years)	4.3	4.1

No stock options or Stock SARs were granted during 2010 or 2011. The Stock SARs contain performance and service conditions. The performance conditions have been met for all awards.

At December 31, 2011, the liability for Stock SARs to be settled in cash was $2.9 million, all of which are vested or are expected to vest within the next 12 months. As of December 31, 2011, unrecognized compensation costs related to unvested Stock SARs to be settled in cash was $0.1 million and will be recognized as stock-based compensation expense over a weighted-average period of 0.41 years.

At December 31, 2011, all stock options were vested and accordingly, the Company had no unrecognized compensation costs related to outstanding stock options. The total intrinsic value (current market price less the exercise price) of stock options exercised during the years ended December 31, 2011, 2010 and 2009 was $3.6 million, $6.0 million, and $0.1 million, respectively, and the Company received $47,000, $0.7 million, and $9,000 in cash in connection with stock option exercises for the years ended December 31, 2011, 2010 and 2009, respectively.

Restricted Stock Awards and Units. The Company began issuing restricted stock awards in 2005 and restricted stock units in 2009. Although shares of common stock are not released to the employee until vesting, restricted stock awards have the right to vote and accordingly, restricted stock awards are considered issued and outstanding at the date of grant. Restricted stock units, which may be settled in cash or common stock at the Company s option, do not have the right to vote and are not considered issued and outstanding until converted into common shares and released to the employee upon vesting. The table below summarizes restricted stock award and unit activity for the years ended December 31, 2011, 2010 and 2009:

	Shares/ Units	Grant-date Fair Value
Unvested restricted stock awards and units at December 31, 2008	341,698	$ 34.93
Granted	529,062	18.76
Vested	(390,655)	25.49
Forfeited	(8,862)	28.81
Unvested restricted stock awards and units at December 31, 2009	471,243	25.01
Granted	640,207	18.60
Vested	(380,668)	23.42
Forfeited	(19,827)	25.23
Unvested restricted stock awards and units at December 31, 2010	710,955	20.26
Granted	567,901	35.27
Vested	(452,585)	25.29
Forfeited	(25,773)	23.30
Unvested restricted stock awards and units at December 31, 2011	800,498	$ 27.96

As of December 31, 2011, unrecognized compensation costs related to unvested restricted stock awards and units was $14.4 million and will be recognized as stock-based compensation expense over a weighted-average period of two years. The 2009, 2010 and 2011 grants of certain restricted stock units contained performance and service conditions. The performance conditions have been met for all awards.

Cash-Settled Stock Appreciation Rights Plan

In June 2009, the Company established the Carrizo Oil & Gas, Inc. Cash-Settled Stock Appreciation Rights Plan (Cash SARs Plan). The Cash SARs Plan enables employees and independent contractors to share in the appreciation of Carrizo s common stock, but does not require the issuance of shares. During 2011 and 2010, the Company issued 153,801 and 408,804 Cash SARs, respectively. At December 31, 2011 and 2010, the liability for Cash SARs was $6.5 million and $4.3 million, of which, $5.2 million and $2.7 million are classified as other accrued liabilities representing the portion of the awards that are vested or are expected to vest within the next 12 months, with the remainder of $1.3 million and $1.6 million, classified as other long-term liabilities, respectively.

The following table summarizes the weighted-average assumptions used in the Black-Scholes-Merton option pricing model to calculate the fair value of the Cash SARs at December 31, 2011:

	Granted in 2011	Granted in 2010
December 31, 2011 fair value	$ 18.50	$ 23.06
Volatility factor	61.6%	60.3%
Dividend yield		
Risk-free interest rate	0.4%	1.8%
Expected term (in years)	2.9	4.5

As of December 31, 2011, unrecognized compensation costs related to unvested Cash SARs was $2.3 million and will be recognized as stock-based compensation expense over a weighted-average period of 1.7 years. The 2011 grants of Cash SARs contained performance and service conditions. The performance conditions have been met for all awards.

10. RELATED PARTY TRANSACTIONS

Transactions with Avista and affiliates

Utica Shale Joint Venture. In September 2011, the Company entered into a joint venture with affiliates of Avista to acquire and develop acreage in the liquids rich region of the Utica Shale. The properties initially dedicated to the joint venture consist of approximately 15,000 net acres in eastern Ohio and northwestern Pennsylvania. Under the terms of the agreement, the Company owns an initial 10% interest in the joint venture properties with Avista owning the remaining 90%. Avista has the right to contribute aggregate funds of up to $130.0 million to the joint venture, with the ability to raise this amount by an incremental $70.0 million. The Company holds two purchase options to increase its participating interest to 50% in the properties initially dedicated to the joint venture and subsequently acquired by the joint venture that expire in September 2012 and March 2013, respectively. The Company s purchase options may be exercised at specified increments above acreage cost and associated improvements at any time during the applicable option period. The exercise deadlines for both options are accelerated in connection with a sale by Avista of substantially all of its interests in the joint venture properties. In the event these purchase options are not exercised and the Company is not selling substantially all of its interest in the joint venture (except in connection with such a sale by Avista), the Company will be entitled to share in any cash distributions by Avista to its partners, provided specified return on investment thresholds on Avista s investment are achieved, with the percentage of such cash distributions to the Company increasing if higher rates of return on investment thresholds are achieved. The Company will initially serve as operator of the joint venture properties and will provide certain management services to Avista related to the joint venture.

Steven A. Webster, Chairman of the Company s Board of Directors, serves as Co-Managing Partner and President of Avista Capital Holdings, LP, which has the ability to control Avista. ACP III s Board of Managers have the sole authority for determining whether, when and to what extent any cash distributions will be declared and paid to members of ACP III. Mr. Webster is not a member of ACP III s Board of Managers.

Marcellus Shale Joint Ventures. Effective August 1, 2008, Carrizo Marcellus, a wholly-owned subsidiary of the Company, entered into a joint venture arrangement with ACP II, an affiliate of Avista. In September 2010, the Company completed the sale of 20% of its interests in substantially all of its oil and gas properties in Pennsylvania that had been subject to the Avista joint venture to Reliance Marcellus II, LLC (Reliance), a wholly-owned subsidiary of Reliance Holding USA, Inc. and an affiliate of Reliance Industries Limited for $13.1 million in cash and a commitment by Reliance to pay 75% of certain of the Company s future development costs up to approximately $52.0 million. The proceeds were recognized as a reduction of proved oil and gas properties, net and 20% of the unevaluated leasehold and seismic costs associated with these properties (approximately $16.0 million) was also transferred to proved oil and gas properties, net. Simultaneously with the closing of this transaction, ACP II closed the sale of its entire interest in the same properties to Reliance for a purchase price of approximately $327.0 million. At the time of entering into the agreements for these transactions, the Company and Avista agreed that B Unit distributions to the Company with respect to Avista s sale of properties to Reliance would be principally based upon Avista s return on investment and internal rates of return associated with such properties, subject to amounts withheld from distribution by ACP II s board. In connection with these sales transactions, the Company and Avista amended the participation agreement and other joint venture agreements with Avista to provide that the properties that the Company and Avista sold to Reliance, as well as the properties the Company committed to the new joint venture with Reliance, are not subject to the terms of the Avista joint venture, and that the Avista joint venture s area of mutual interest will generally not include Pennsylvania, the state in which those properties are located. The Company s joint venture with Avista continues and now covers approximately 142,653 net acres, primarily in West Virginia and New York. Pursuant to the terms of the Avista area of mutual interest, effective December 31, 2010, the initial area of mutual interest was reduced to specified halos in which the Avista joint venture was active.

In December 2010, the Company entered into a settlement agreement with Reliance providing for the resolution of defects in title that Reliance alleged with respect to the properties it acquired from the Company and Avista in September 2010. In the agreement, the Company agreed to undertake specified curative measures with respect to the properties it and Avista sold to Reliance, and to indemnify Reliance on its own behalf and on behalf of Avista with respect to specified third party claims (in addition to existing customary indemnification obligations under the purchase agreement). In connection with entering into the settlement agreement, the Company entered into an agreement with Avista by which Avista agreed to indemnify the Company for amounts paid on Avista s behalf by the Company under the settlement agreement, if any.

In June 2011, in accordance with the title and post-closing adjustment provisions of the purchase and sale agreements described above, the Company provided additional interests in oil and gas properties in parts of Pennsylvania in the Marcellus Shale to Reliance in substitution of properties included in the sale that were affected by certain alleged title defects. In exchange for such substitute properties, the Company received $0.3 million in cash from Reliance relating to the sale of 20% of its interest.

On November 16, 2010, Carrizo Marcellus assigned, via distribution and subsequent contribution, its interests in the joint venture with Avista to Carrizo (Marcellus) WV LLC (Carrizo WV), also a wholly-owned subsidiary of the Company. In connection with the assignment, Carrizo Marcellus assigned to Carrizo WV its rights and obligations under the participation agreement, as well as the related joint operating agreement, pursuant to which operatorship of the joint venture was assumed by Carrizo WV. In addition, Carrizo WV and the other parties thereto amended and restated the participation agreement on November 16, 2010, effective as of October 1, 2010. This amended and restated participation agreement amends the participation agreement by, among other things, (i) providing fixed percentages and thresholds for sharing net cash flow from hydrocarbon production and proceeds from the sales of underlying joint venture properties and (ii) eliminating provisions that have been performed and are inapplicable going forward.

The Company serves as operator of the properties covered by the joint venture with Avista under a joint operating agreement with Avista and also performs specified management services for ACP II, the Avista affiliate that is the Company s partner in the joint venture. An operating committee composed of one representative of each party provides overall supervision and direction of joint operations. Avista or its designee has the right to become a co-operator of the properties if all of its membership interests or substantially all of its assets are sold to an unaffiliated third party or if the Company defaults under the terms of any pledge of its interest in the properties.

The Company has agreed to jointly market Avista s share of the production from the properties with its own until the cash flows and sale proceeds are allocated in accordance with the parties participating interests under the joint operating agreement. In connection with the formation of ACP II, Carrizo Marcellus Holding Inc., a wholly-owned subsidiary of the Company, was issued B Units in ACP II which entitle the Company to increasing percentages of cash distributions to affiliates of Avista Capital Partners, LP, if, when, and only to the extent that those cash distributions exceed certain internal rates-of-return and return-on-investment thresholds with respect to Avista s investment as set forth in the limited liability company agreement of ACP II. The business and affairs of ACP II are managed under the direction of a three-member board of managers, consisting of employees and principals of Avista. The B Units have limited rights with respect to the actions of ACP II and no voting rights with respect to the election of managers.

Each party now has ability to transfer its interest in the joint venture to third parties subject in most instances to preferential purchase rights for transfers of less than 10% of its interest in joint venture properties, or to tag along rights for most other transfers.

Steven A. Webster, Chairman of the Company s Board of Directors, serves as Co-Managing Partner and President of Avista Capital Holdings, LP, which has the ability to control Avista. ACP II s Board of Managers have the sole authority for determining whether, when and to what extent any cash distributions will be declared and paid to members of ACP II. Mr. Webster is not a member of ACP II s Board of Managers. As disclosed elsewhere, the Company has been and is a party to prior arrangements with affiliates of Avista Capital Holdings, LP in respect of the Company s joint venture with affiliates of Avista in the Utica Shale and investment in Pinnacle.

ACP II Distributions. During the third and fourth quarters of 2010, the Company received cash distributions aggregating approximately $38.8 million and during the second quarter of 2011 received an additional $3.3 million on its B Unit investment in ACP II, which were recognized as a reduction of capitalized oil and gas property costs.

Advances from Avista and affiliates. Advances for joint operations on the consolidated balance sheets included $9.5 million and $1.2 million as of December 31, 2011 and 2010, respectively, representing the net amounts Avista had advanced the Company related to activity within the Utica and Marcellus Shale joint ventures.

11. DERIVATIVE INSTRUMENTS

The Company relies on various types of derivative instruments to manage its exposure to commodity price risk and to provide a level of certainty in its forward cash flows supporting its capital expenditure program. The derivative instruments typically used are fixed-rate swaps, costless collars, puts, calls and basis differential swaps. Under these derivative instruments, payments are received or made based on the differential between a fixed and a variable product price. These agreements are settled in cash at termination, expiration or exchanged for physical delivery contracts. The Company s current long-term strategy is to manage exposure for a substantial, but varying, portion of forecasted production up to 36 months. The derivative instruments are carried at fair value in the consolidated balance sheets, with the changes in fair value recognized as gain (loss) on derivative instruments, net in the consolidated statements of operations for the period in which the changes occur.

The fair value of derivative instruments at December 31, 2011 was a net asset of $37.3 million, of which 68% was with Credit Suisse, 19% was with BNP Paribas, 6% was with Shell Energy North America (US) LP, 5% was with Credit Agricole, and the remaining 2% was with Societe Generale. The fair value of derivative instruments at December 31, 2010 was a net asset of $24.1 million, of which 74% was with Credit Suisse, 14% was with Shell Energy North America (US) LP, 9% was with Credit Agricole, and the remaining 3% was with BNP Paribas. Master netting agreements are in place with these counterparties. Because the counterparties are either investment grade financial institutions or an investment grade international oil and gas company, the Company believes it has minimal credit risk and accordingly does not currently require its counterparties to post collateral to support the asset positions of its derivative instruments. As such, the Company is exposed to credit risk to the extent of nonperformance by the counterparties to its derivative instruments. Although the Company does not currently anticipate such nonperformance, it continues to monitor the financial viability of its counterparties. Because Credit Suisse, BNP Paribas, Credit Agricole, and Societe Generale are lenders in the Company s Revolving Credit Facility, the Company is not required to post collateral with respect to derivatives instruments in a net liability position with these counterparties as the contracts are secured by the Revolving Credit Facility.

The following sets forth a summary of the Company s natural gas derivative positions at average delivery location (WAHA and Houston Ship Channel) prices as of December 31, 2011.

Period	Volume (in MMbtu)	Weighted Average Floor Price ($/MMbtu)	Weighted Average Ceiling Price ($/MMbtu)
2012	18,943,000	$ 5.43	$ 5.56
2013	10,950,000	$ 5.07	$ 5.07

In connection with the derivative instruments above, the Company has entered into protective put spreads. In 2012, at market prices below the short put price of $4.77, the floor price becomes the market price plus the put spread of $1.28 on 7,572,400 of the 18,943,000 MMBtus and the remaining 11,370,600 MMBtus have a floor price of $5.43.

Period	Volume (in MMbtu)	Weighted Average Short Put Price ($/MMbtu)	Weighted Average Put Spread ($/MMbtu)
2012	7,572,400	$ 4.77	$ 1.28

In addition to the table above, the Company sold call positions of 3,650,000 MMBtus at a price of $5.50 per MMBtu for 2014.

The following sets forth a summary of the Company s U.S. crude oil derivative positions at average NYMEX prices as of December 31, 2011.

Period	Volume (in Bbls)	Weighted Average Floor Price ($/Bbls)	Weighted Average Ceiling Price ($/Bbls)
2012	1,024,800	$ 82.57	$ 101.83
2013	839,500	$ 83.48	$ 102.55

For the years ended December 31, 2011, 2010 and 2009, the Company recorded the following gains and losses related to its oil and gas derivative instruments:

	Year Ended December 31,		
	2011	2010	2009
		(In thousands)	
Realized gain (loss) on derivative instruments, net	$ 35,452	$ 33,218	$ 74,866
Unrealized gain (loss) on derivative instruments, net	11,539	14,564	(33,401)
Gain (loss) on derivative instruments, net	$ 46,991	$ 47,782	$ 41,465

The Company deferred the payment of premiums associated with certain of its oil and gas derivative instruments totaling $1.2 million and $3.9 million at December 31, 2011 and December 31, 2010, respectively. The Company classified $0.4 million and $3.9 million as other current liabilities at December 31, 2011 and December 31, 2010, respectively, and $0.8 million as other non-current liabilities at December 31, 2011. There were no other non-current liabilities at December 31, 2010. These deferred premiums will be paid to the counterparty with each monthly settlement (April 2012 March 2014) and recognized as a reduction of realized gain (loss) on derivative instruments, net.

12. FAIR VALUE MEASUREMENTS

Accounting guidelines for measuring fair value establish a three-level valuation hierarchy for disclosure of fair value measurements. The valuation hierarchy categorizes assets and liabilities measured at fair value into one of three different levels depending on the observability of the inputs employed in the measurement. The three levels are defined as follows:

Level 1 Observable inputs such as quoted prices in active markets at the measurement date for identical, unrestricted assets or liabilities.

Level 2 Other inputs that are observable directly or indirectly such as quoted prices in markets that are not active, or inputs which are observable, either directly or indirectly, for substantially the full term of the asset or liability.

Level 3 Unobservable inputs for which there is little or no market data and which the Company makes its own assumptions about how market participants would price the assets and liabilities.

Assets and Liabilities Measured at Fair Value on a Recurring Basis

The following tables present the Company s assets and liabilities measured at fair value on a recurring basis as of December 31, 2011 and 2010, and indicate the fair value hierarchy of the valuation techniques utilized by the Company to determine such fair value:

December 31, 2011	Level 1	Level 2	Level 3	Total
		(In thousands)		
Assets				
Derivative instruments	$	$ 61,073	$	$ 61,073
Liabilities				
Derivative instruments		(23,792)		(23,792)
Total	$	$ 37,281	$	$ 37,281

December 31, 2010	Level 1	Level 2	Level 3	Total
		(In thousands)		
Assets				
Investment in Pinnacle	$ 869	$	$	$ 869
Derivative instruments		48,140		48,140
Liabilities				
Derivative instruments		(24,062)		(24,062)
Total	$ 869	$ 24,078	$	$ 24,947

The fair values of derivative instruments are based on a third-party pricing model which utilizes inputs that include (a) quoted forward prices for oil and gas, (b) discount rates, (c) volatility factors and (d) current market and contractual prices, as well as other relevant economic measures. The estimates of fair value are compared to the values provided by the counterparty for reasonableness. Derivative instruments are subject to the risk that counterparties will be unable to meet their obligations. Such non-performance risk is considered in the valuation of the Company s derivative instruments, but to date has not had a material impact on estimates of fair values. The fair values reported in the consolidated balance sheets are as of a point in time and subsequently change as these estimates are revised to reflect actual results, changes in market conditions and other factors. The assets and liabilities for derivative instruments included in the tables above are presented on a gross basis. The assets and liabilities for derivative instruments included in the consolidated balance sheets are presented on a net basis when such amounts are with the same counterparty and subject to master netting agreements. The Company had no transfers in or out of Levels 1 or 2 for the years ended December 31, 2011 and 2010.

Fair Value of Other Financial Instruments

The Company s other financial instruments consist of cash and cash equivalents, receivables, payables and short-term and long-term debt. The carrying amounts of cash and cash equivalents, receivables, payables and short-term debt approximate fair value due to the highly liquid or short-term nature of these instruments. The carrying amounts of long term debt under the Prior Credit Facility, the Revolving Credit Facility and the Huntington Facility (each as defined in Note 6. Debt) approximate fair value as these borrowings bear interest at variable rates of interest. The fair value of the Convertible Senior Notes at December 31, 2011 and 2010 was estimated at approximately $73.0 million and $71.9 million, respectively, based on quoted market prices. The fair value of the Senior Notes at December 31, 2011 and 2010 was estimated at approximately $606.0 million and $412.0 million, respectively, based on quoted market prices, with an increase of $194.0 million due to the issuance of the additional $200 million of Senior Notes in November 2011.

Other Fair Value Measurements

The initial measurement of asset retirement obligations at fair value is calculated using discounted future cash flows of internally estimated costs. Significant Level 3 inputs used in the calculation of asset retirement obligations include the costs of plugging and abandoning wells, the costs of surface restoration and reserve lives. See Note 7. Asset Retirement Obligations for a table setting forth the Company s asset retirement obligations.

13. CONDENSED CONSOLIDATING FINANCIAL INFORMATION

In November 2010 and November 2011, the Company and certain of the Company s wholly owned subsidiaries (such subsidiaries collectively, the Subsidiary Guarantors) issued in private placements $400.0 million and $200.0 million, respectively, aggregate principal amount of the Company s Senior Notes. Certain, but not all, of the Company s wholly owned subsidiaries have issued full, unconditional and joint and several guarantees of the Senior Notes and may guarantee future issuances of debt securities. In connection with both offerings, the Company subsequently filed Form S-4 Registration Statements with the SEC to exchange the previously issued privately placed notes for notes registered under the Securities Act of 1933, as amended. On May 4, 2011, two of the Subsidiary Guarantors, CCBM, Inc. and Chama Pipeline Holding LLC, were released from their respective guarantees of the Senior Notes and the Convertible Senior Notes and were subsequently dissolved. On August 5, 2011, two recently formed wholly owned subsidiaries of the Company, Carrizo (Eagle Ford) LLC and Carrizo (Niobrara) LLC, guaranteed the Senior Notes and the Convertible Senior Notes. These entities also guarantee borrowings under the Revolving Credit Facility.

The rules of the SEC require that condensed consolidating financial information be provided for a subsidiary that has guaranteed the debt of a registrant issued in a public offering, where the guarantee is full, unconditional and joint and several and where the voting interest of the subsidiary is 100% owned by the registrant. The Company is, therefore, presenting condensed consolidating financial information as of December 31, 2011 and December 31, 2010, and for each of the three years ended December 31, 2011, 2010 and 2009 on a parent company, combined guarantor subsidiaries, combined non-guarantor subsidiaries, eliminating entries, and consolidated basis and should be read in conjunction with the consolidated financial statements. The financial information may not necessarily be indicative of results of operations, cash flows, or financial position had the Subsidiary Guarantors operated as independent entities.

Investments in subsidiaries are accounted for by the respective parent company using the equity method for purposes of this presentation. Results of operations of subsidiaries are therefore reflected in the parent company s investment accounts and earnings. The principal elimination entries set forth below eliminate investments in subsidiaries and intercompany balances and transactions. Typically in a condensed consolidating financial statement, the net income and equity of the parent company equals the net income and equity of the consolidated entity. The Company s oil and gas properties are accounted for using the full cost method of accounting whereby impairments and DD&A are calculated and recorded on a country by country basis. However, when calculated separately on a legal entity basis, the combined totals of parent company and subsidiary impairments and DD&A can be more or less than the consolidated total as a result of differences in the properties each entity owns including amounts of costs incurred, production rates, reserve mix, future development costs, etc. Accordingly, elimination entries are required to eliminate any differences between consolidated and parent company and subsidiary company combined impairments and DD&A.

CARRIZO OIL & GAS, INC.

CONDENSED CONSOLIDATING BALANCE SHEETS

	December 31, 2011				
	Parent Company	Combined Guarantor Subsidiaries	Combined Non-Guarantor Subsidiaries	Eliminations	Consolidated
			(In thousands)		
ASSETS					
Current assets	$ 1,349,841	$ 71,018	$ 3,874	$ (1,304,336)	$ 120,397
Property and equipment, net	101,015	1,131,672	68,911	8,916	1,310,514
Investment in subsidiaries	(58,764)			58,764	
Other assets	38,853	54,062	9,133	(5,279)	96,769
Total assets	$ 1,430,945	$ 1,256,752	$ 81,918	$ (1,241,935)	$ 1,527,680
LIABILITIES AND SHAREHOLDERS EQUITY					
Current liabilities	$ 150,793	$ 1,368,456	$ 4,366	$ (1,252,295)	$ 271,320
Long-term liabilities	724,801	2,183	22,429	(2,908)	746,505
Shareholders equity	555,351	(113,887)	55,123	13,268	509,855
Total liabilities and shareholders equity	$ 1,430,945	$ 1,256,752	$ 81,918	$ (1,241,935)	$ 1,527,680

	December 31, 2010				
	Parent Company	Combined Guarantor Subsidiaries	Combined Non-Guarantor Subsidiaries	Eliminations	Consolidated
			(In thousands)		
ASSETS					
Current assets	$ 1,029,000	$ 22,733	$	$ (991,401)	$ 60,332
Property and equipment, net	194,243	784,790		4,024	983,057
Investment in subsidiaries	(139,829)			139,829	
Other assets	99,876	78,288		(77,419)	100,745
Total assets	$ 1,183,290	$ 885,811	$	$ (924,967)	$ 1,144,134
LIABILITIES AND SHAREHOLDERS EQUITY					
Current liabilities	$ 85,783	$ 1,024,622	$	$ (991,401)	$ 119,004
Long-term liabilities	644,315	1,018		(76,839)	568,494
Shareholders equity	453,192	(139,829)		143,273	456,636
Total liabilities and shareholders equity	$ 1,183,290	$ 885,811	$	$ (924,967)	$ 1,144,134

CARRIZO OIL & GAS, INC.

CONDENSED CONSOLIDATING STATEMENTS OF OPERATIONS

	For the Year Ended December 31, 2011				
	Parent Company	Combined Guarantor Subsidiaries	Combined Non-Guarantor Subsidiaries	Eliminations	Consolidated
			(In thousands)		
Oil and gas revenues	$ 31,875	$ 170,292	$	$	$ 202,167
Cost and expenses	68,793	100,255	177	(4,891)	164,334
Operating income (loss)	(36,918)	70,037	(177)	4,891	37,833
Other income and (expense), net	41,182	(21,188)	(2,978)		17,016
Income (loss) before income taxes	4,264	48,849	(3,155)	4,891	54,849
Income tax (expense) benefit	(55)	(22,612)	6,237	(1,790)	(18,220)
Equity in income (loss) of subsidiaries	29,319			(29,319)	
Net income (loss)	$ 33,528	$ 26,237	$ 3,082	$ (26,218)	$ 36,629

	For the Year Ended December 31, 2010				
	Parent Company	Combined Guarantor Subsidiaries	Combined Non-Guarantor Subsidiaries	Eliminations	Consolidated
			(In thousands)		
Oil and gas revenues	$ 33,203	$ 104,920	$	$	$ 138,123
Cost and expenses	65,106	55,815		(4,024)	116,897
Operating income (loss)	(31,903)	49,105		4,024	21,226
Other income and (expense), net	4,974	(10,521)			(5,547)
Income (loss) before income taxes	(26,929)	38,584		4,024	15,679
Income tax (expense) benefit	9,264	(13,542)		(1,451)	(5,729)
Equity in income (loss) of subsidiaries	25,042			(25,042)	
Net income (loss)	$ 7,377	$ 25,042	$	$ (22,469)	$ 9,950

	For the Year Ended December 31, 2009				
	Parent Company	Combined Guarantor Subsidiaries	Combined Non-Guarantor Subsidiaries	Eliminations	Consolidated
			(In thousands)		
Oil and gas revenues	$ 38,245	$ 74,454	$	$	$ 112,699
Cost and expenses	113,205	337,725		754	451,684
Operating income (loss)	(74,960)	(263,271)		(754)	(338,985)

Other income and (expense), net	29,207	(8,374)			20,833
Income (loss) before income taxes	(45,753)	(271,645)		(754)	(318,152)
Income tax (expense) benefit	15,815	96,357		1,135	113,307
Equity in income (loss) of subsidiaries	(175,288)			175,288	
Net income (loss)	$ (205,226)	$ (175,288)	$	$ 175,669	$ (204,845)

CARRIZO OIL & GAS, INC.

CONDENSED CONSOLIDATING STATEMENTS OF CASH FLOWS

	For the Year Ended December 31, 2011				
	Parent Company	Combined Guarantor Subsidiaries	Combined Non-Guarantor Subsidiaries	Eliminations	Consolidated
			(In thousands)		
Net cash provided by operating activities	$ 56,357	$ 98,948	$ (967)	$	$ 154,338
Net cash used in investing activities	(194,285)	(356,168)	(36,334)	300,789	(285,998)
Net cash provided by financing activities	155,644	261,773	39,016	(300,789)	155,644
Net increase (decrease) in cash and cash equivalents	17,716	4,553	1,715		23,984
Cash and cash equivalents, beginning of period	1,418	2,710			4,128
Cash and cash equivalents, end of period	$ 19,134	$ 7,263	$ 1,715	$	$ 28,112

	For the Year Ended December 31, 2010				
	Parent Company	Combined Guarantor Subsidiaries	Combined Non-Guarantor Subsidiaries	Eliminations	Consolidated
			(In thousands)		
Net cash provided by operating activities	$ 24,781	$ 69,635	$	$	$ 94,416
Net cash used in investing activities	(200,871)	(268,069)		198,644	(270,296)
Net cash provided by financing activities	176,171	198,644		(198,644)	176,171
Net increase (decrease) in cash and cash equivalents	81	210			291
Cash and cash equivalents, beginning of period	1,337	2,500			3,837
Cash and cash equivalents, end of period	$ 1,418	$ 2,710	$	$	$ 4,128

	For the Year Ended December 31, 2009				
	Parent Company	Combined Guarantor Subsidiaries	Combined Non-Guarantor Subsidiaries	Eliminations	Consolidated
			(In thousands)		
Net cash provided by operating activities	$ 75,919	$ 57,453	$	$	$ 133,372
Net cash used in investing activities	(102,753)	(151,541)		91,841	(162,453)
Net cash provided by financing activities	27,734	91,841		(91,841)	27,734
Net increase (decrease) in cash and cash equivalents	900	(2,247)			(1,347)
Cash and cash equivalents, beginning of period	437	4,747			5,184
Cash and cash equivalents, end of period	$ 1,337	$ 2,500	$	$	$ 3,837

14. SUPPLEMENTAL DISCLOSURES ABOUT OIL AND GAS PRODUCING ACTIVITIES (UNAUDITED)

The Company s oil and gas properties are located in the U.S. and U.K.

Costs Incurred

Costs incurred in oil and gas property acquisition, exploration and development activities are summarized below:

	Year Ended December 31,		
	2011	2010 (In thousands)	2009
U.S.			
Property acquisition costs			
Unproved	$ 108,212	$ 126,783	$ 35,248
Proved			
Exploration costs	374,366	134,487	77,255
Development costs	19,769	62,952	55,270
Asset retirement obligations	3,369	1,031	(1,390)
Total costs incurred	$ 505,716	$ 325,253	$ 166,383
U.K.			
Property acquisition costs			
Unproved	$ 1,004	$ 806	$
Proved			
Exploration costs			
Development costs	38,775	5,375	
Asset retirement obligations	2,649		
Total costs incurred	$ 42,428	$ 6,181	$
Total Worldwide			
Property acquisition costs			
Unproved	$ 109,216	$ 127,589	$ 35,248
Proved			
Exploration costs	374,366	134,487	77,255
Development costs	58,544	68,327	55,270
Asset retirement obligations	6,018	1,031	(1,390)
Total costs incurred	$ 548,144	$ 331,434	$ 166,383

Costs incurred excludes capitalized interest on U.S. unproved properties of $23.4 million, $20.7 million, and $19.7 million for the years ended December 31, 2011, 2010 and 2009, respectively, and includes capitalized internal costs directly identified with acquisition, exploration, and development activities of $9.6 million, $5.3 million, and $5.6 million for the years ended December 31, 2011, 2010 and 2009, respectively.

Proved Oil and Gas Reserve Quantities

Proved reserves are generally those quantities of oil and gas, which by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be economically producible in future years from known reservoirs under existing economic conditions, operating methods and government regulations. Proved developed reserves include proved reserves that can be expected to be produced through existing wells with existing equipment and operating methods or in which the cost of the required equipment is relatively minor compared to the cost of a new well. Proved undeveloped reserves are generally proved 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.

Proved oil and gas reserve quantities at December 31, 2011, 2010 and 2009, and the related discounted future net cash flows before income taxes are based on estimates prepared by LaRoche Petroleum Consultants, Ltd., Ryder Scott Company Petroleum Engineers, and Fairchild and Wells. Such estimates have been prepared in accordance with guidelines established by the SEC.

The Company s net proved oil and gas reserves and changes in net proved oil and gas reserves, which are located in the U.S. and U.K., are summarized below:

	Millions of Cubic Feet of Natural Gas at December 31,		
	U.S.	**U.K.**	**Worldwide**
Proved developed and undeveloped reserves			
January 1, 2009	392,736		392,736
Extensions and discoveries	196,400		196,400
Revisions of previous estimates	(42,867)		(42,867)
Sales of reserves in place	(3,195)		(3,195)
Production	(30,027)		(30,027)
End of year - December 31, 2009	513,047		513,047
Proved developed reserves at beginning of year	216,229		216,229
Proved developed reserves at end of year	292,695		292,695
Proved undeveloped reserves at beginning of year	176,507		176,507
Proved undeveloped reserves at end of year	220,352		220,352
January 1, 2010	513,047		513,047
Extensions and discoveries	240,347	4,684	245,031
Revisions of previous estimates	(54,132)		(54,132)
Production	(34,095)		(34,095)
End of year - December 31, 2010	665,167	4,684	669,851
Proved developed reserves at beginning of year	292,695		292,695
Proved developed reserves at end of year	358,543		358,543
Proved undeveloped reserves at beginning of year	220,352		220,352
Proved undeveloped reserves at end of year	306,624	4,684	311,308
January 1, 2011	665,167	4,684	669,851
Extensions and discoveries	221,544		221,544
Revisions of previous estimates	(41,990)	154	(41,836)
Sales of reserves in place	(82,884)		(82,884)
Production	(38,990)		(38,990)
End of year - December 31, 2011	722,847	4,838	727,685
Proved developed reserves at beginning of year	358,543		358,543
Proved developed reserves at end of year	389,795	2,419	392,214

Proved undeveloped reserves at beginning of year	306,624	4,684	311,308
Proved undeveloped reserves at end of year	333,052	2,419	335,471

	Barrels of Crude Oil, Condensate and Natural Gas Liquids at December 31, (In thousands)		
	U.S.	U.K.	Worldwide
Proved developed and undeveloped reserves			
January 1, 2009	18,308		18,308
Extensions and discoveries	2,373		2,373
Revisions of previous estimates	(5,375)		(5,375)
Production	(503)		(503)
End of year - December 31, 2009	14,803		14,803
Proved developed reserves at beginning of year	7,869		7,869
Proved developed reserves at end of year	6,898		6,898
Proved undeveloped reserves at beginning of year	10,439		10,439
Proved undeveloped reserves at end of year	7,905		7,905
January 1, 2010	14,803		14,803
Extensions and discoveries	10,961	5,263	16,224
Revisions of previous estimates	(2,102)		(2,102)
Production	(452)		(452)
End of year - December 31, 2010	23,210	5,263	28,473
Proved developed reserves at beginning of year	6,898		6,898
Proved developed reserves at end of year	7,387		7,387
Proved undeveloped reserves at beginning of year	7,905		7,905
Proved undeveloped reserves at end of year	15,823	5,263	21,086
January 1, 2011	23,210	5,263	28,473
Extensions and discoveries	17,404		17,404
Revisions of previous estimates	(71)	174	103
Sales of reserves in place	(10,310)		(10,310)
Production	(1,011)		(1,011)
End of year - December 31, 2011	29,222	5,437	34,659
Proved developed reserves at beginning of year	7,387		7,387
Proved developed reserves at end of year	7,989	2,719	10,708
Proved undeveloped reserves at beginning of year	15,823	5,263	21,086
Proved undeveloped reserves at end of year	21,233	2,718	23,951

Natural gas extensions and discoveries are primarily attributable to the following:

2011	Additions of U.S. proved developed and undeveloped reserves as a result of drilling and offset locations in the Barnett Shale, Marcellus Shale, and Eagle Ford Shale. Transfer of U.K. proved undeveloped reserves to proved developed reserves as a result of drilling.
2010	Additions of U.S. proved developed and undeveloped reserves as a result of drilling and offset locations in the Barnett Shale and Eagle Ford Shale, as well as an increase in previously estimated proved undeveloped reserves based on operational performance; Additions of U.K. proved undeveloped reserves as a result of the approval of the Huntington Field Development Plan by the Company and its joint venture partners and the U.K. Department of Energy and Climate Change in November 2010.
2009	Additions to proved developed and undeveloped reserves as a result of drilling and additional offset locations in the Barnett Shale recognized under the oil and gas reserve estimation and disclosure requirements which the Company adopted effective December 31, 2009.

Natural gas revisions of previous estimates are primarily attributable to the following:

2011	Negative price revisions primarily in the Barnett Shale.
2010	Positive price revisions offset by negative quantity revisions due to a planned shift in future drilling priorities focusing more on drilling in the core of the Barnett Shale, which resulted in removing natural gas reserves previously classified as proved undeveloped in the Barnett Shale.
2009	Negative price revisions primarily in the Barnett Shale and Gulf Coast.

Natural gas sales of reserves in place are primarily attributable to the following:

2011	Sales of properties to KKR during the second quarter and GAIL during the third quarter.

Crude oil, condensate and natural gas liquids extensions and discoveries are primarily attributable to the following:

2011	Additions of U.S. proved developed and undeveloped reserves as a result of drilling and offset locations in the Eagle Ford Shale and the Niobrara Formation; Transfer of U.K. proved undeveloped reserves to proved developed reserves as a result of drilling.
2010	Additions of U.S. proved developed and undeveloped reserves as a result of drilling and offset locations in the Eagle Ford Shale; Additions of U.K. proved undeveloped reserves as a result of the approval of the Huntington Field Development Plan by the Company and its joint venture partners and the U.K. Department of Energy and Climate Change in November 2010.
2009	The oil and gas reserve estimation and disclosure requirements, which the Company adopted effective December 31, 2009, resulted in the removal of 5.4 MMBbls of crude oil reserves previously classified as proved undeveloped in the Camp Hill Field that were not associated with wells that were expected to be both drilled prior to December 31, 2014 and into which the Company then planned to inject steam prior to December 31, 2014.

Crude oil, condensate and natural gas liquids sales of reserves in place are primarily attributable to the following:

2011	Sales of properties to KKR during the second quarter and GAIL during the third quarter.

Standardized Measure

The standardized measure of discounted future net cash flows relating to proved oil and gas reserves is as follows:

	For the Years Ended December 31,		
	U.S.	U.K.	Worldwide
2011			
Future cash inflows	$ 4,834,725	$ 617,667	$ 5,452,392
Future production costs	(1,212,722)	(95,229)	(1,307,951)
Future development costs	(1,163,377)	(43,954)	(1,207,331)
Future income taxes	(477,824)	(246,273)	(724,097)
Future net cash flows	1,980,802	232,211	2,213,013
Less 10% annual discount to reflect timing of cash flows	(1,124,339)	(47,638)	(1,171,977)
Standard measure of discounted future net cash flows	$ 856,463	$ 184,573	$ 1,041,036
2010			
Future cash inflows	$ 3,514,978	$ 432,230	$ 3,947,208
Future production costs	(952,148)	(96,782)	(1,048,930)
Future development costs	(597,444)	(78,439)	(675,883)
Future income taxes	(415,021)	(128,618)	(543,639)
Future net cash flows	1,550,365	128,391	1,678,756
Less 10% annual discount to reflect timing of cash flows	(895,681)	(34,289)	(929,970)
Standard measure of discounted future net cash flows	$ 654,684	$ 94,102	$ 748,786
2009			
Future cash inflows	$ 2,150,293	$	$ 2,150,293
Future production costs	(943,774)		(943,774)
Future development costs	(297,023)		(297,023)
Future income taxes	(73,656)		(73,656)
Future net cash flows	835,840		835,840
Less 10% annual discount to reflect timing of cash flows	(453,747)		(453,747)
Standard measure of discounted future net cash flows	$ 382,093	$	$ 382,093

Effective December 31, 2009, the Company adopted the new requirements for oil and gas reserve estimation and disclosure which require that reserve estimates and future cash flows be based on the average market prices for sales of oil and gas on the first calendar day of each month during the year. The average prices used for 2011, 2010 and 2009 under these rules were $95.28, $74.39, and $56.10 per barrel, respectively, for crude oil and condensate, $44.90, $35.18 and $23.18 per barrel, respectively, for natural gas liquids, and $3.24, $3.50 and $3.30 per Mcf, respectively, for natural gas.

Future operating expenses and development costs are computed primarily by the Company s petroleum engineers by estimating the expenditures to be incurred in developing and producing the Company s proved oil and gas reserves at the end of the year, based on year end costs and assuming continuation of existing economic conditions. Future income taxes are based on year-end statutory rates, adjusted for the tax basis of oil and gas properties and available applicable tax assets. A discount factor of 10% was used to reflect the timing of future net cash flows. The standardized measure of discounted future net cash flows is not intended to represent the replacement cost or fair value of the Company s oil and gas properties. An estimate of fair value would also take into account, among other things, the recovery of reserves not presently classified as proved, anticipated future changes in prices and costs, and a discount factor more representative of the time value of money and the risks inherent in oil and gas reserve estimates.

Changes in Standardized Measure

Changes in the standardized measure of discounted future net cash flows relating to proved oil and gas reserves are summarized below:

	Year Ended December 31, 2011	2010	2009
Changes in Standardized Measure:			
Standardized measure beginning of year	$ 748,786	$ 382,093	$ 510,949
Revisions to reserves proved in prior years:			
Net change in sales prices and production costs related to future production	263,477	263,663	(254,511)
Net change in estimated future development costs	(4,653)	83	108,831
Net change due to revisions in quantity estimates	(51,782)	(25,451)	(71,840)
Accretion of discount	100,624	39,833	59,589
Changes in production rates (timing) and other	(94,293)	49,806	(70,616)
Total revisions	213,373	327,934	(228,547)
Net change due to extensions and discoveries, net of estimated future development and production costs	508,558	351,831	76,419
Net change due to sales of minerals in place	(150,437)		748
Sales of oil and gas produced, net of production costs	(173,853)	(115,800)	(80,997)
Previously estimated development costs incurred	45,160	43,940	34,816
Net change in income taxes	(150,551)	(241,212)	68,705
Net change in standardized measure of discounted future net cash flows	292,250	366,693	(128,856)
Standardized measure end of year	$ 1,041,036	$ 748,786	$ 382,093

15. SELECTED QUARTERLY FINANCIAL DATA (UNAUDITED)

The following table presents summarized quarterly financial information for the years ended December 31, 2011 and 2010:

2011	**First**	**Second**	**Third**	**Fourth**
	(In thousands, except per share amounts)			
Revenues	$ 44,058	$ 50,672	$ 51,668	$ 55,769
Costs and expenses, net	(43,323)	(42,930)	(30,025)	(49,259)
Net income (loss)	$ 735	$ 7,742	$ 21,643	$ 6,510
Basic net income (loss) per share	$ 0.02	$ 0.20	$ 0.56	$ 0.17
Diluted net income (loss) per share	$ 0.02	$ 0.20	$ 0.55	$ 0.16

2010	**First**	**Second**	**Third**	**Fourth**
	(In thousands, except per share amounts)			
Revenues	$ 38,956	$ 32,922	$ 30,502	$ 35,743
Costs and expenses, net	(19,220)	(31,137)	(17,668)	(60,148)(1)
Net income (loss)	$ 19,736	$ 1,785	$ 12,834	$ (24,405)
Basic net income (loss) per share	$ 0.64	$ 0.05	$ 0.37	$ (0.69)
Diluted net income (loss) per share	$ 0.63	$ 0.05	$ 0.37	$ (0.69)

(1) The fourth quarter of 2010 includes a pre-tax loss on extinguishment of debt of $31.0 million.

The sum of the individual quarterly basic and diluted income (loss) per share amounts may not agree with year-to-date basic and diluted income (loss) per share as each quarterly computation is based on the weighted average number of common shares outstanding during that period. In addition, the sum of the individual quarterly revenues, costs and expenses, net and net income (loss) may not agree with year-to-date totals due to rounding.

SIGNATURES

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

CARRIZO OIL & GAS, INC.

By: /s/ Paul F. Boling
Paul F. Boling
Chief Financial Officer, Vice President, Secretary and Treasurer

Date: February 29, 2012

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.

Name	Capacity	Date
/s/ S. P. Johnson IV	President, Chief Executive Officer and Director	February 29, 2012
S. P. Johnson IV	(Principal Executive Officer)	
/s/ Paul F. Boling	Chief Financial Officer, Vice President,	February 29, 2012
Paul F. Boling	Secretary and Treasurer	
	(Principal Financial Officer)	
/s/ David L. Pitts	Vice President and Chief Accounting Officer	February 29, 2012
David L. Pitts	(Principal Accounting Officer)	
/s/ Steven A. Webster	Chairman of the Board	February 29, 2012
Steven A. Webster		
/s/ Thomas L. Carter, Jr.	Director	February 29, 2012
Thomas L. Carter, Jr.		
/s/ F. Gardner Parker	Director	February 29, 2012
F. Gardner Parker		
/s/ Roger A. Ramsey	Director	February 29, 2012
Roger A. Ramsey		
/s/ Frank A. Wojtek	Director	February 29, 2012
Frank A. Wojtek		