CARRIZO OIL & GAS INC
Form 10-K
March 16, 2010

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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, 2009
Commission No. 0-22915
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.)

1000 Louisiana Street, Suite 1500, 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 o NO þ

Indicate by check mark if the registrant is not required to file reports pursuant to Section 13 or Section 15(d) of the Exchange Act.

YES o NO 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 o

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 o NO o

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

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, 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 o	Accelerated filer þ	Non-accelerated filer o (Do not check if a smaller reporting company)	Smaller reporting company o

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Act).

YES o NO þ

At June 30, 2009, the aggregate market value of the registrant s Common Stock held by non-affiliates of the registrant was approximately $486.0 million based on the closing price of such stock on such date of $17.15.

At March 10, 2010, the number of shares outstanding of the registrant s Common Stock was 30,888,890.

DOCUMENTS INCORPORATED BY REFERENCE

Portions of the definitive proxy statement for the Registrant s 2010 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, 2009.

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Forward-Looking Statements.

The statements contained in all parts of this document, including, but not limited to, those relating to our schedule, targets, estimates or results of future drilling, including the number, timing and results of wells, budgeted wells, increases in wells, the timing and risk involved in drilling follow-up wells, expected working or net revenue interests, planned expenditures, prospects budgeted and other future capital expenditures, risk profile of natural gas and oil exploration, acquisition of 3-D seismic data (including number, timing and size of projects), spending plans, capital expenditure plans, planned evaluation of prospects, probability of prospects having natural gas and oil, expected production or reserves, increases in reserves, acreage, working capital requirements, hedging activities, the ability of expected sources of liquidity to implement our business strategy, accessibility of borrowings under our credit facility, borrowing base increases under our credit facility, future exploration activity, production rates, financing for our 2010 exploration and development program, project financing, growth in production, development of new drilling programs, participation of our industry partners, funding for our Marcellus Shale operations, hedging of production, exploration and development expenditures, evaluation of properties for impairment, Camp Hill steam injection, results of new drilling technology and development, all and any other statements regarding future operations, financial results, business plans and cash needs and other statements that are not historical facts are forward looking statements. When used in this document, the words anticipate, budgeted, planned, targeted, potential, estimate, expect, project, believe and similar expressions are intended to be among the statements that identify forward looking statements. Such statements involve risks and uncertainties, including, but not limited to, those relating to the continued economic downturn, availability of financing our dependence on our exploratory drilling activities, the volatility of natural gas and oil prices, the need to replace reserves depleted by production, operating risks of natural gas and oil operations, our dependence on our key personnel, factors that affect our ability to manage our growth and achieve our business strategy, technological changes, our significant capital requirements, the potential impact of government regulations, including related to hydraulic fracturing and air emissions, climate change, adverse regulatory determinations, litigation, competition, the uncertainty of reserve information and future net revenue estimates, property acquisition risks, availability of equipment, access to pipelines and gathering systems, weather, availability of financing, actions of lenders financial condition of our industry partners and the counterparties to our hedges, ability to obtain permits and other factors detailed herein and in our other filings with the Securities and Exchange Commission (the Commission). Some of the factors that could cause actual results to differ from those expressed or implied in forward-looking statements are described under Item 1A. Risk Factors and in other sections of this 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 forward-looking statements. Each forward-looking statement speaks only as of the date of the particular statement and we undertake no obligation to update or revise any forward-looking statement.

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

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PART I

Item 1. and Item 2. Business and Properties

OVERVIEW

General

Carrizo Oil & Gas, Inc. is an independent energy company which, together with its subsidiaries (collectively, Carrizo, the Company or we) is engaged in the exploration, development, production and transportation of natural gas and oil, principally in the United States. Our current operations are principally focused in proven, producing natural gas plays known as shale plays or resource plays . Our primary core area is the Barnett Shale area in North Texas (Barnett Shale or Fort Worth Barnett Shale), with a focus on Southeast Tarrant County, Texas. Through our wholly-owned subsidiary Carrizo (Marcellus) LLC, we have also established a core area in another emerging resource play, the Marcellus Shale area in Pennsylvania, New York, West Virginia and Virginia. In addition to the Barnett and the Marcellus, we are active in other project areas comprised of: (1) other shale plays, including the Eagle Ford in South Texas, Fayetteville in Arkansas, Barnett/Woodford in West Texas/New Mexico, Floyd/Neal in Mississippi, the Bakken in North Dakota and the New Albany in Kentucky/Illinois, (2) traditional geologic trends along the onshore Gulf Coast area in Texas, Louisiana and Alabama, primarily in the Miocene, Wilcox, Frio and Vicksburg trends, (3) the U.K. North Sea, including the Huntington Field discovery, and (4) the Camp Hill heavy oil steam flood project in East Texas.

We seek to grow our production through our 3-D seismic-driven exploratory and development drilling program and by applying proven horizontal drilling and hydraulic-fracturing (known as fracing) technology. From our inception through December 31, 2009, we have participated in the drilling of 786 wells (392.8 net) with an apparent success rate of approximately 85%. In the last five years, our apparent success rate has been 100% in the Barnett Shale. Since mid 2003, when we participated in drilling our first Barnett Shale well, we have participated in over 281 wells (207.9 net) in the Barnett Shale play. During 2009, we participated in the drilling of 47 gross wells (32.7 net) wells in the Barnett Shale, including 39 gross wells that we operated. As of December 31, 2009, we had grown our proved reserves in the Barnett Shale to 569.7 Bcfe and our net average annual production in the Barnett Shale to 72.1 MMcfe/d. In 2009, we also began ramping up our drilling activity in the Marcellus Shale play where we participated in the drilling of seven gross wells (2.3 net), including 4 gross wells that we operated. All of these wells were vertical wells to evaluate our acreage. None of the wells that we have drilled to date in the Marcellus Shale play have yet been placed on production, although we expect several of them to be hooked up and commence production in late 2010 or early 2011.

Since we began focusing a significant portion of our efforts in shale plays, particularly in the Barnett Shale, we have grown our reserves at a compounded annual growth rate (CAGR) of 43%, while simultaneously maintaining a CAGR on our production of 28%. During 2009, we added, net of production, 132.3 Bcfe to proved reserves, or a reserve replacement ratio of 400%. Please read Oil and Natural Gas Reserve Replacement for more information on our reserve replacement ratio. This reserve replacement ratio was achieved in spite of record production of 33.0 Bcfe, a 29% increase from 2008, including 30.5 Bcfe from wells that we drilled and operated. At year-end 2009, our proved reserves were approximately 85% natural gas and approximately 15% crude oil, condensate and natural gas liquids.

Our Board of Directors has approved an initial capital expenditure plan of $170 million for 2010. This plan reflects our strategy of controlling capital costs and maintaining financial flexibility in light of current economic conditions and represents a substantial decrease from our capital expenditures of $548.8 million and $224.9 million in, 2008 and 2007, respectively. We currently expect to commit the majority of our capital expenditures plan for 2010 on continued development of our Barnett Shale core area and development of our Marcellus Shale properties. We intend to finance our 2010 capital expenditure plan primarily from cash flow from operations. Other available sources of funding include our senior credit facility, proceeds from the possible selective sale of non-core assets, project financing and joint ventures where partners are required to carry a portion of our capital costs.

Barnett Shale Area

We began active participation in the Barnett Shale area in the Fort Worth Basin through acquisition of acreage located west of the city of Fort Worth, Texas in mid 2003. By year-end 2009, we had interests in 242 gross (175.2 net) producing wells and 39 gross (32.7 net) non-producing wells that were drilled and waiting on completion and/or pipeline connection in the Barnett Shale. Of these wells, we operated 163 gross producing wells and 38 gross wells drilled but not yet producing.

During 2010, we intend to pursue a deliberate strategy of reducing the inventory of drilled wells that are waiting on fracing and completion that we built during 2009. We currently expect that at the end of 2010, we will have approximately 19 gross (15.1 net) wells waiting on completion and/or hookup.

We continue to focus significant efforts on our Tarrant County urban drilling program. On our initial urban pad site on the University of Texas at Arlington campus, we brought six wells on production in November 2008. We drilled our second set of 16 wells from this well pad during 2009 and into early 2010. As of year-end 2009, we were operating three rigs in the Barnett Shale, all of which are drilling exclusively horizontal wells. We currently expect to operate all three rigs in the Barnett Shale throughout 2010.

We currently expect to invest approximately $134 million in 2010 to drill an additional 57 gross (38.1 net) wells in this area, and to fracture, complete and bring on production approximately 74 gross (53.2 net) wells, and to make strategic land acquisitions to complete our leasing within prospect areas in order to bring them to drill-ready status.

Marcellus Shale Area

In late 2007, we established a new core area in the Marcellus Shale play, primarily in upstate New York, Pennsylvania and West Virginia. The Marcellus Shale formation is located at depths of 4000 to 9000 , is substantially larger in aerial extent than the Barnett Shale play (over 63 million acres compared to approximately 2.0 million acres in the core areas of the Barnett Shale) and, 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 area to effectively explore for and develop natural gas in the Marcellus Shale.

As of year-end 2009, we held interests in approximately 259,510 gross (106,818 net) acres in the Marcellus Shale, principally in central and northeastern Pennsylvania, West Virginia and New York. Our 2010 capital expenditure plan for the Marcellus Shale area is $31 million. We currently expect to participate in 11 gross (3.8 net) Marcellus Shale play area wells in 2010, including three vertical wells and eight horizontal wells. The actual number of wells that we are able to participate in may be less than this due, in part, to difficulties in obtaining drilling permits. See Item 1A. Risk Factors We have limited experience drilling wells in the Marcellus Shale and less information regarding reserves and declining rates in the Marcellus Shale than in other areas of our operations. We may face difficulties in securing and operating under authorizations and permits to drill for and or operate our Marcellus Shale wells.

Other Project Areas

We currently expect to spend approximately $5 million in land, lease, drilling and other capital and exploration expenditures in 2010 for all of our other projects including the Eagle Ford, Bakken, and Fayetteville Shale plays, the U.K. North Sea, the Gulf Coast and our Camp Hill Field. During 2010, we currently expect to participate in drilling up to three gross (1.5 net) wells in the Gulf Coast and other shale plays in which we hold an interest. In our Camp Hill Field we currently expect to continue steaming, complete the refurbishment of two steam generators and move steam lines to connect existing injector wells to these facilities as they are completed. In our other traditional oil and gas plays in the Gulf Coast, we will focus on workover, well intervention and lease maintenance to maintain existing production at as high a rate as feasible.

U.K. North Sea Area

We currently hold interests in seven licenses in the U.K. North Sea, all but one of which are located in the Central Graben area. We have been successful in acquiring new acreage in four of the last five UK bid rounds, with a 57% overall bidding success rate on blocks which we have bid since 2003. We operate four of our U.K. licenses.

We continue to pursue a low entry cost business model in the U.K. North Sea that allows us to acquire prospective acreage inexpensively without making firm well commitments. Subsequent drilling is conducted via joint venture partnerships that provide for a carried interest on the initial exploration well. This strategy has directly led to the successful Huntington discoveries. The Huntington Forties project has been fully appraised and is currently in pre-development. The Huntington Fulmar project is still being appraised.

We currently plan to spend at least $2.0 million in 2010 on development planning for the Huntington Forties development. Once the Huntington Forties development plan is sanctioned by our partners, which may occur as early as mid-2010, our net share of 2010 Huntington development costs could approach $20 million. Because the project has not yet been sanctioned, and sanction may be delayed for any number of reasons, we have chosen to treat these additional costs as contingent. If the project is sanctioned, we would be required to revise our capital expenditure plans, and in such case it would be our current intent to either finance the majority of

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development costs for the Huntington Field through an off-balance sheet project financing or to sell all or a portion of our interest in the Huntington Field if we receive an acceptable offer. If project development stays on track, and governmental approval of the development plan is received from the U.K. government later this year, we currently believe that first production from the Huntington Forties reservoir could occur as early as late 2011 or early 2012.

In addition to our main activity at Huntington, our recent exploration efforts have generated 15 new exploration prospects in various stages of maturity on the other licenses that we control and our working interests in these prospects range from 25-100%. By virtue of our bid evaluation strategy, each prospect is within reach of existing infrastructure, all within ten miles of established facilities. The estimated cost to satisfy all remaining work obligations to maintain our existing licenses with the U.K. government in the North Sea is approximately $1.1 million. We are also currently planning to participate in the upcoming 26th license round that was recently announced by the U.K. government.

Business Strategy

Measured Growth Through the Drillbit

Our objective is to create shareholder value through the execution of a business strategy designed to capitalize on our strengths. Key elements of our business strategy include:

Control Capital Costs and Maintain Financial Flexibility. In response to continued reduced demand for natural gas and lower natural gas prices as a result of the recent economic downturn, we have announced our capital and exploration expenditure plan for 2010 to be $170 million. Although this reflects an increase from the capital plan in 2009, we continue to strive to maintain our financial flexibility, while achieving a positive production growth profile. Any further deterioration in commodity prices may cause us to reduce our capital and exploration expenditure plan for 2010.

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 exploratory drilling success rate in the onshore Gulf Coast area of 85% over the last seven years and our 100% drilling success rate in the Barnett Shale area since inception in 2003. During 2010, we plan to drill approximately 57 gross (38.1 net) wells in the Barnett Shale area, eleven gross (3.8 net) wells in the Marcellus Shale area and three gross (1.5 net) well in other company project areas. We have planned approximately $170 million for capital expenditures in 2010, approximately $145 million of which we expect to use for drilling activities, including $130 million in the Barnett Shale area, $20 million for leasehold and seismic in the Marcellus and Barnett Shale areas and $5 million in other project areas, including development planning in the North Sea.

Focus on Areas Where We Have Experience and a Technical Advantage. We focus our activities in the industry-proven Barnett Shale in which our wells have generally longer-lived reserves and where our management, technical staff and field operations teams have significant experience and, we believe, a technical advantage derived from operating over 200 horizontal wells. We are attempting to leverage this advantage in other shale trends, principally in the Marcellus and the Eagle Ford Shales. We plan to focus a majority of our near-term capital expenditures in the Barnett Shale area, where we have acquired a significant acreage position and accumulated a large drillsite inventory, and in the Marcellus Shale, where our joint venture currently controls over 213,636 net acres.

Maintain a Conservative Exploration and Development Portfolio. In recent years, we have sought to more heavily weight our drilling program toward projects with relatively lower risk and moderate potential, such as our development drilling in the Barnett Shale, than to projects that have relatively higher risk, but substantial upside potential such as our onshore Gulf Coast projects.

Manage Risk Exposure by Market Testing Prospects and Optimizing Working Interests. 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 when others are capital constrained. Our joint ventures with Avista in the Marcellus Shale, that commenced in August 2008, and with Sumitomo Corporation in the Barnett Shale that we announced in November 2009, are recent and prominent examples of this strategy. Additionally, we rely on advanced technologies, including 3-D seismic analysis, to better define geologic risks, thereby enhancing the results of our drilling efforts. The use of 3-D seismic analysis does not guarantee that hydrocarbons are present or, if present, that they can be recovered economically.

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Retain and Incentivize a Highly Qualified Technical Staff. We employ 38 natural gas and oil professionals, including geophysicists, petrophysicists, geologists, petroleum engineers and production and reservoir engineers and technical support staff, who have an average of over 20 years of experience. This level of expertise and experience gives us an in-house ability to apply advanced technologies to our drilling and production activities, including our extensive experience in fracing and horizontal drilling technologies. Our technical staff is granted stock-based awards and participates in an incentive bonus pool based on production resulting from our exploratory successes.

EXPLORATION APPROACH

In the Barnett Shale area, as well as other emerging resource plays such as the Marcellus Shale, our exploration strategy has been to accumulate significant leasehold positions with known shale thickness and thermal maturity in the proximity of known or emerging pipeline infrastructures. An additional component of our business strategy, particularly in urban areas within the Barnett Shale play, we 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 from them. We next acquire 3-D seismic data to assist in well placement and in optimizing the development plan for the units surrounding the well pad sites. Even in the relatively lower-risk, reserve-proven trends, such as the Barnett Shale trend, 3-D seismic data interpretation is instrumental in our exploration approach, significantly reducing geologic risk and allowing optimized reserve development. Finally, we form drilling units and utilize sophisticated horizontal drilling, multi-stage simultaneous fracing programs and micro-seismic techniques designed to maximize the potential flow rate and producible 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. For example, in 2009 we entered into a strategic alliance with a subsidiary of Sumitomo Corporation of Japan, wherein we sold it a 12.5% working interest in 16 of our drilling units in the Barnett Shale. Sumitomo will pay approximately 16.7% of the drilling and completion costs on future wells to earn the 12.5% working interest in the wells that we currently expect to drill in those units. In certain instances we also seek to maximize the acreage that we can hold by drilling and producing in the Barnett Shale 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 fracing, 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 (both 2-D and 3-D) and timely project evaluation through the drillbit to ensure that we minimize the costs to test for locations for commercial reserves while building a significant lease position. Our first exploration wells in these trends are frequently vertical wells because they allow us to acquire the necessary thermal maturity and rock property data, while also permitting us to test various fracing and completion techniques without incurring the cost of drilling horizontal wells.

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. Our current project areas result from leads developed primarily by our internal staff. 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 operation rights. Specific drill-sites are typically chosen by our own geoscientists or, in urban 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 area and along the Texas and Louisiana Gulf Coast. We believe that the experience we have gained in the Barnett Shale area, along with our extensive experience in fracing 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 and onshore Gulf Coast, 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, 2009, we operated 286 gross producing oil and natural gas wells. We generally seek to control operations for most new exploration and development in the Barnett Shale area, taking advantage of our technical staff experience in horizontal drilling and hydraulic fracing. During 2009, we operated 39 of the 47 gross wells that we participated in drilling in the Barnett Shale and four of the seven gross wells that we participated in drilling in the Marcellus Shale.

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SIGNIFICANT PROJECT AREAS

Our operations are focused primarily in the Barnett Shale trend in North Texas and in the Marcellus Shale in New York, Pennsylvania, West Virginia and Virginia and in the onshore Gulf Coast area extending from South Louisiana to South Texas. Our other areas of interest include the U.K. North Sea, other shale trends in South Texas, North Dakota, West Texas, New Mexico, Mississippi, Kentucky, Illinois and Arkansas and the Camp Hill Field in Texas. The table below highlights our main areas of activity:

	Productive Wells		3-D Seismic Data	Net Leased	Drilling Capital Expenditures	
	Gross	Net	(Sq. Miles)	Acres	2009	2010 Plan
					(In millions)	
Barnett Shale	242	175.2	663	52,166	$ 124.0	$ 130.0
Marcellus Shale	1	0.2	7	106,818	3.2	15.0
Other Project Areas in the U.S.	202	113.5	11,057	338,108	4.0	
U.K. North Sea			2,057	140,346		
Total	445	288.9	13,784	637,438	$ 131.2	$ 145.0

Barnett Shale Area

As of December 31, 2009, we had approximately 72,508 gross and 52,166 net mineral acres under lease and 4,920 gross and 1,862 net mineral acres subject to lease options in the Barnett Shale. Nearly 51% of our total Barnett Shale lease acreage, totaling 36,717 gross acres, is either in currently designated producing units or in units on which wells have been drilled and are awaiting fracing and completion and/or hookup. During 2009, we drilled 47 additional gross wells (32.7 net), of which we operated 39. In addition, we fractured, completed and brought on production 62 gross (39.6 net) wells during 2009. Net proved reserves grew by 32% from 432.1 Bcfe on December 31, 2008 to 569.7 Bcfe on December 31, 2009.

Since 2005, we have drilled only horizontal wells in the Barnett Shale area. Our Barnett horizontal wells generally have target depths of 8,500 to 13,500 feet including the lateral section. Typical costs to drill and complete a Barnett Shale horizontal well ranged from approximately $2.2 million to $4.3 million during 2009. While we experienced some decline in drilling costs in the last year, we currently expect the cost of fracing and completion to increase moderately in 2010 due to increased fracing and completion activity compared to the depressed levels experienced in 2009. In 2008, we tested a new drilling strategy called stagger stack drilling in which we drill two layers of horizontal wells and simultaneously frac them. We have now observed an extended production test of this technology on one of our well sites. We believe that the results of this test are an encouraging development in producing the thicker sections of the Barnett Shale. We plan to perform additional tests during 2010, comparing the results to conventional wells drilled in 2010 with the objective of permitting us to achieve a higher density of wells without significantly sacrificing either reserves or production, leading to an increase in the number of potential development locations, and higher ultimate recovery on our Barnett Shale acreage.

Marcellus Shale Area

As of December 31, 2009, we owned interests in 259,510 gross (106,818 net) acres in the Marcellus shale trend, principally in Pennsylvania, New York and West Virginia.

Effective as of August 1, 2008, our wholly-owned subsidiary Carrizo (Marcellus) LLC entered into a joint venture arrangement with an affiliate of Avista Capital Partners, LP, a private equity fund (Avista Capital Partners, LP, together with its affiliates, Avista). See Notes to Consolidated Financial Statement Note 9. Related Party Transactions. Under the terms of the joint venture, we and Avista each committed to contribute up to $150 million in cash and properties to acquire and develop acreage within an area of mutual interest located in the Marcellus Shale play, including the dedication of all of our respective Marcellus leasehold owned at the time of the formation of the joint venture. Until mid-2009, Avista was required to fund substantially all of the joint venture s capital and exploration obligations and our general and administrative expenses. Since that time, we and Avista have each borne our respective share of all costs of joint venture operations in accordance with our participating interests, which to date remains 50/50.

We serve as operator of our joint venture with Avista under a joint operating agreement with Avista and provide all geotechnical, engineering, operating, land and accounting support to the joint venture. We have also agreed to perform specified management services for the Avista affiliate that is our partner in the joint venture on the same cost and reimbursement basis provided for in the joint operating agreement. An operating committee composed of one representative of each party provides overall supervision and direction of joint operations. Each representative has a vote equal to the participating interest in the properties and operations of the party it represents. 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 we default under the terms of any pledge of our interest in the properties.

Subject to specified exceptions, net cash flow from hydrocarbon production from the Marcellus joint venture properties and related sales proceeds, if the properties are sold, will be allocated first to the joint venture partners in proportion to their respective investments (with property dedications generally valued on a cost basis) until Avista has recovered its investment, then 100% to us until we recover approximately $33.5 million, and thereafter in accordance with the parties participating interests, which we expect will generally be 50/50. We have also agreed to jointly market Avista s share of the production from the properties with our own until the cash flows and sale proceeds are allocated in accordance with the parties participating interests under the joint operating agreement. In addition to our share in the production and sale proceeds from joint venture properties, we also acquired as part of the transaction (through a wholly-owned subsidiary) an interest in the Avista joint venture entity that entitles us to increasing percentages of the Avista entity s profits if that entity s members receive a return of their investment, and specified internal rates of return on these investments are achieved. Our interest in the Avista entity provides consent rights only in limited, specified circumstances and generally does not entitle us to vote or participate in the management of the Avista entity, which is controlled by its members and affiliates.

As part of the transaction, and subject to certain exceptions, the parties agreed to enter into an area of mutual interest covering the Marcellus Shale play, wherein any lease, royalty or mineral rights acquired by one party within the area must be proportionately offered to the other on the same terms and conditions. The area of mutual interest 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: (1) December 31, 2010, (2) the date on which the parties collective investment reaches $300 million, (3) upon Avista s request to be designated (or have its designee designated) as a co-operator of the properties in connection with the sale to an unaffiliated third party of all of its membership interests or substantially all of its assets and (4) upon the required designation of Avista (or its designee) as a co-operator of the properties in connection with our default under the terms of any pledge of our interest in the properties.

The parties have limited rights to transfer their respective interests in the properties until the initial parties collective investment reaches $300 million. We currently expect that collective expenditures during 2010 will cause the joint venture to exceed the $300 million dollar limitation. After that time, each party s ability to transfer its interest in the joint venture to third parties is 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. Avista s tag along rights do not apply upon a change of control of Carrizo.

During 2009, we drilled seven gross (2.3 net) vertical wells to test our acreage, including one in New York, three in Pennsylvania and three wells in West Virginia, of which we operated four gross (2.0 net) wells. Based upon the encouraging results from these wells, we expect to attempt to complete at least six of these wells as producers once pipeline infrastructure has been completed. We participated in our first 3-D seismic program as well.

Other Project Areas

In 2009, we had capital and exploration expenditures of $8.5 million on projects other than the Barnett and Marcellus Shales, the U.K. North Sea and the Camp Hill Field in Texas. We drilled nine gross (1.2 net) wells in these project areas during this period , including two gross (1.0 net) wells in the Onshore Gulf Coast, one of which was an apparent success, and one of which we operated. In our other projects we participated in seven gross (0.2 net) wells during 2009.

We continue to evaluate our acreage, seismic and well data to high grade projects in these other areas. Regional mapping of shale extent, depth, thickness, organic content, thermal maturation, mineralogy, as well as cost and availability of leases, are analyzed to define the project fairways to lease, and to assist in identifying the locations for initial exploratory wells. Among other shale plays, we have been successful in acquiring approximately 34,809 gross

(26,587 net) acres in the Fayetteville Shale in Arkansas as of December 31, 2009. In 2010, we currently plan to further evaluate our acreage position and data in our possession in our shale plays and to participate principally in wells that are operated by third parties, particularly in the Fayetteville Shale, where a number of industry partners are active. Recently, we also commenced actively leasing in the Eagle Ford Shale trend in South Texas.

In recent years, we have also drilled wells in the Wilcox, Smackover and Frio/Vicksburg trends of the Gulf Coast area where our exploration team has many years of experience. Our Gulf Coast projects generally consist of geologically complex natural gas objectives well-suited for drilling using 3-D seismic evaluation. We have data licenses for approximately 8,788 square miles of 3-D seismic data and control 17,872 net acres of leasehold in the Gulf Coast area. From January 1, 2004 through December 31, 2009, we drilled and completed 102 wells (31.4 net) in the Gulf Coast area on 120 attempts.

Camp Hill Field

We own interests in approximately 1,120 gross acres in the Camp Hill Field in Anderson County, Texas and operate all of these leases. During 2009, the project produced an average of 34.8 Bbls/d of 19 API gravity oil. During 2009, as a result of the drilling activity in 2005-2008, during which we drilled 67 wells, we added a number of new data points that led to a remapping of the field. As a consequence, we have revised our development plan to initially focus on those portions of the Camp Hill Field which we believe will provide the best production response to steaming. In addition, we focused our efforts on the completion of wells, the repair of one steam generator, the installation of steam and flow lines in the field and the continued development of the steam flood. In September 2009 we recommenced steaming in the field.

The wells drilled in the Camp Hill Field produce from a depth of 500 feet and utilize a tertiary steam drive as an enhanced oil recovery process. Although efficient at maximizing oil recovery, the steam drive process is relatively expensive to operate because natural gas or produced crude is burned to create the steam injectant. Lifting costs during the year ended December 31, 2009 averaged $73.48 per barrel ($12.25 per Mcfe). Costs were high, as expected, because oil production response typically lags the startup of steam injection. The oil produced, although viscous, commands a comparable price to the West Texas Intermediate crude due to its suitability as a lube oil feedstock.

As a result of the adoption of new Commission rules regarding the reporting of oil and natural gas reserves, we removed all tertiary reserves previously classified as proved in the Camp Hill Field that are not associated with wells that will be both drilled prior to December 31, 2014 and into which we plan to inject steam prior to December 31, 2014. This action resulted in a significant write-down in our proved reserves. The collective impact of all of the changes reflected in the 2009 reserves report, including the adoption of the new reserves reporting rules and the revision of our field development plan, led to the removal of approximately 6.9MM gross (5.4MM net) barrels of proved tertiary reserves from our books that are currently expected to be developed and produced in 2015 and beyond. These reserves were substantially all previously classified as proved undeveloped reserves and had been included in our previous reserve reports for many years. As of December 31, 2009, we had 2.8 MMBbls of net proved oil reserves in this project, with 1.6 MMBbls of such proved oil reserves currently classified as developed, and 1.2 MMBbls are currently classified as proved undeveloped. On an energy equivalent basis, proved reserves in the Camp Hill Field constituted less than 3% of our total proved reserves at December 31, 2009. Although we firmly believe that a substantial amount of these oil reserves are still present and recoverable with existing technology and at existing prices, we will not classify this resource as proved reserves until we believe they will be developed within five years of the date of the applicable reserves report.

To develop the remaining proved undeveloped reserves in the Camp Hill Field, we currently expect to spend approximately $1.1 million to drill an additional five producer (and no injector) wells between 2010 and the end of 2014, lay additional steam and flow lines, and complete repairs and refurbishment of two additional steam generators that are currently in the field in order to increase steam generation capacity and to add additional steam patterns to the current steam flood. We also currently estimate that during that time period, we will also incur total operating costs, including the purchase of natural gas to generate steam, of approximately $42.2 million. The precise timing and amount of our expenditures to develop the proved undeveloped reserves in this project will depend on several factors, including the relative prices of oil and natural gas.

These proved reserves are based on a number of engineering and operational assumptions that we believe to be reasonable. Among the engineering assumptions, we assume an ultimate recovery factor of 49% of oil in place. We believe this recovery efficiency is reasonable, particularly in light of the fact that a project that we have operated in the Camp Hill Field since 1993 has demonstrated a 49% recovery efficiency as of December 31, 2009 and is currently still producing. These proved reserves are also based on our assumed oil/steam ratio (barrel oil produced/Mcf of steam injected) for the Camp Hill Field, which as of December 31, 2009 was 0.212 over the remaining life of the field. Although we believe that this oil/steam ratio is reasonable, we note that this assumed oil/steam ratio is slightly more favorable than the historic oil/steam ratio of 0.18 recorded at the nearby Slocum Field, which we believe is analogous to the Camp Hill Field. The engineering assumptions we use are estimates and final results may vary, possibly materially, from these estimates. A negative variance could materially impact both the amount of recoverable reserves and the profitability of the project.

We acquired our initial interest in the Camp Hill Field in 1993. Production to date has been limited as we have experienced various delays in the development of the field, and there can be no assurance that there will not be additional delays. The primary operational assumption that impacts the quantity of proved reserves, as well as production rates, is the capacity and the availability of

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steam generators. There are currently four steam generators associated with the field, two of which are operational and two of which are undergoing refurbishment this year. We currently assume the availability of four steam generators for the life of current reserves. We have had difficulties maintaining desired levels of steam injection in the field over the last several years, partly due to the availability of emission permits for the generators, and partially due to mechanical problems with the generators. In our most recent development plan, we assume that we will not obtain any additional emission capacity beyond what is currently available under existing permits (although this is less than the absolute capacity of the generators) and that the generators will continue to operate at recent historical efficiencies. Once steaming commences, it takes up to 16 months in certain parts of the field before the full effects of the steaming are evident. The impact of a negative variance from this steam response assumption will not directly reduce our proved reserves from prior estimates, except as it results in a delay in moving from one pattern to the next due to insufficient steaming capacity. However, it will extend the productive life of the field with a corresponding reduction in the present value of the estimated future net revenues discounted at 10% per annum.

U.K. North Sea Area

We currently hold interests in seven licenses covering just over 275,146 gross acres in the U.K. North Sea. Our primary project area is the Huntington Field project area located principally on block 22/14b, where we have a 15% working interest. The Huntington discoveries are located in water depths of approximately 300 feet, were drilled and, with regards to our Huntington Forties reservoir, subsequently appraised in 2007. In late 2008, two wells were drilled by the joint venture in the adjoining block 22/14a, one of which confirmed a modest extension of the Huntington Forties field onto that license. We commenced preliminary development planning for the Huntington Forties reservoir in 2009. This process is nearing completion and we currently hope to select a preferred development concept with our Huntington joint venture partners as early as the second quarter of 2010. However, failure of the joint venture in the adjoining block 22/14a to engage our joint venture in meaningful unitization discussions could have a material adverse impact on this schedule. 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 sell our interest on terms that are acceptable to us or at all. We currently believe that production from this field will not commence until at least late 2011 or early 2012.

During 2009, we were also successful in obtaining interests in four new exploration licenses, each of which has an initial term of at least two years and no drilling commitments. At the end of the license s initial term, a decision to drill a well, or drop each of the four licenses must be made. If the decision is made to commit to drill a well, we and our partners in that license will have two years to drill a well on that license. No such decision has yet been made on any license that we obtained in 2009. The total remaining committed work obligation on these four licenses is approximately $1.1 million.

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 budget 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 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 may currently be part of our capital plan 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. Our final determination of whether to drill any scheduled or budgeted wells 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 natural gas and oil and the availability and prices of drilling rigs and 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 drillsites or budgeted wells discussed will, if drilled, encounter reservoirs of commercially productive oil or natural 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.

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

Oil and Natural Gas Reserves

The following table sets forth our estimated net proved oil and natural gas reserves and the PV-10 value of such reserves as of December 31, 2009. The reserve data and the present value as of December 31, 2009 were prepared by LaRoche Petroleum Consultants, Ltd., Fairchild & Stan, Inc., and Ryder Scott Company. For further information concerning these independent engineers estimates of our proved reserves at December 31, 2009, 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 natural gas prices for each month in the prior twelve-month period as of the calculation date, discounted at 10% per annum on a pretax basis, and is not intended to represent the current market value of the estimated oil and natural gas reserves owned by us. For further information concerning the present value of future net revenues from these proved reserves, see Notes 2 and 12 of Notes to Consolidated Financial Statements.

Summary of Oil and Gas Reserves as of December 31, 2009
Based on Average 2009 Prices
(Dollars in thousands)

	Oil, Condensate, and Natural Gas Liquids (MBbls)	Natural Gas (MMcf)	Total (MMcfe)[1]	PV-10 Value [2] [3]
PROVED [4]				
Developed	6,898	292,695	334,085	$ 343,771
Undeveloped	7,905	220,351	267,780	54,559
Total Proved	14,803	513,046	601,865	398,330

(1) Natural gas equivalents are determined using the ratio of 6 Mcf of natural gas to 1 Bbl of crude oil.

(2) The PV-10 value as of December 31, 2009 is pre-tax and was determined by using the unweighted average of oil and natural gas prices at the

beginning of each month in the twelve-month period prior to December 31, 2009 sales prices, which averaged $56.10 per Bbl of oil, $23.18 per Bbl of natural gas liquids and $3.30 per Mcf of natural gas. 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 professional analysts and sophisticated 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 natural gas properties. Further, investors may utilize the measure as a basis for comparison of the relative size and value of our reserves to other companies. Management also uses this pre-tax measure when assessing the potential return on investment related to its oil and natural gas properties and in evaluating acquisition candidates. 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 natural 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 $73.7 and $16.2 million, respectively. Accordingly, the after-tax PV-10 value of Total Proved Reserves (or Standardized Measure of Discounted Future Net Cash Flows) is $382.1 million.

(4) All our proved reserves are located within

the United
States.

Proved Undeveloped Reserves

At December 31, 2009 and 2008, we had 267.8 Bcfe and 239.1 Bcfe of proved undeveloped reserves, respectively. In 2009, we added 134.6 Bcfe of proved undeveloped reserves as a result of drilling and additional offset locations permitted under new oil and gas reserve guidelines adopted by the Commission. During 2009, we converted 56.6 Bcfe of reserves from proved undeveloped to proved developed in the Barnett Shale as we continue to focus on our drilling efforts in this area. During 2009, we removed 49.3 Bcfe of total proved undeveloped reserves from our previously reported reserves, of which (a) 22.9 Bcfe was attributable to proved undeveloped reserves in the Camp Hill Field, the development of which was not expected to be initiated within five years, (b) 23.1 Bcfe was attributable to decreases in commodity prices, and (c) 3.3 Bcfe was attributable to performance related revisions. Please read Item 1. and Item 2. Business and Properties - Significant Project Areas Other Project Areas Camp Hill Field for a description of the history of the Camp Hill field, including reasons for certain delays in our development activities.

Costs incurred relating to the development of proved undeveloped reserves were approximately $34.8 million in 2009. Costs incurred relating to the development of proved undeveloped reserves are currently projected to be approximately $75.5 million in 2010, $105.9 million in 2011, and $88.2 million in 2012. All proved undeveloped reserves drilling locations are scheduled to be drilled prior to the end of 2014. For our proved undeveloped reserves associated with our Camp Hill steamflood project, the development of such reserves (including the injection of steam into drilled wells) is scheduled to begin prior to the end of 2014.

No estimates of proved reserves comparable to those included herein have been included in reports to any federal agency other than the Commission. 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.

Our future oil and natural 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 Commission regulations, LaRoche Petroleum Consultants, Ltd., Fairchild & Stan, Inc., and Ryder Scott Company Petroleum Engineers each used the price based on the unweighted average of oil and natural gas prices at the beginning of each month in the twelve-month period prior to December 31, 2009, 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 natural gas production subsequent to December 31, 2009. 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 569.7 Bcfe, or 94.7% of our proved reserves, for the year ended December 31, 2009, which reserves were located on our Barnett Shale properties. Fairchild & Stan, Inc. determined 16.7 Bcfe, or 2.8% of our proved reserves, for the year ended December 31, 2009, which reserves were located on our properties in the Camp Hill Field. Ryder Scott Company Petroleum Engineers determined 15.5 Bcfe, or 2.5% of our proved reserves, for the year ended December 31, 2009, which reserves were located on our Gulf Coast and all other remaining properties.

Qualifications of Third Party Engineers

As discussed above, we engaged LaRoche Petroleum Consultants, Ltd., Fairchild & Stan, Inc. and Ryder Scott Company Petroleum Engineers, 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 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 reviewed by senior management, including the Chief Executive Officer and the Chief Operating Officer.

Oil and Natural Gas Reserve Replacement

Finding and developing sufficient amounts of natural gas and crude oil reserves at economical costs are critical to our long-term success. Given the inherent decline of hydrocarbon reserves resulting from the production of those reserves, 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. In that regard, it might be noted that percentage of reserves that were producing has steadily increased to 45.0% in 2009, from 41.8% in 2008, and from 38.2% in 2007. Set forth below is our reserve replacement ratio for the years ended December 31, 2009, 2008 and 2007.

	2009	2008	2007
Reserve Replacement Ratio	400%	705%	887%

Volumes, Prices and Oil & Natural Gas 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 natural gas for the periods indicated.

	Year Ended December 31,		
	2009	2008	2007
Production volumes			
Oil (MBbls)	174	186	241
Natural gas (MMcf)(1)	32,002	24,513	16,042
Natural gas equivalent (MMcfe)	33,044	25,632	17,487
Average sales prices			
Oil (per Bbl)	$ 58.85	$ 99.74	$ 71.42
Natural gas (per Mcf)	3.20	7.80	6.77
Natural gas equivalent (per Mcfe)	3.41	8.19	7.19
Average production costs (per Mcfe)(2)	$ 0.91	$ 1.28	$ 1.16

(1) Includes 1,975.2 and 965.7 MMcfe of natural gas liquids in 2009 and 2008 respectively.

(2) 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

The table below reconciles our calculation of finding cost to our costs incurred in the purchase of proved and unproved properties and in development and exploration activities, excluding capitalized interest on unproved properties of $19.7 million, $20.5 million and $11.7 million for the years ended December 31, 2009, 2008 and 2007, respectively. We have also included capitalized overhead in our finding cost of $5.6 million, $7.8 million and $4.5 million for the years ended December 31, 2009, 2008 and 2007, respectively. We have also included non-cash asset retirement obligations of $(1.4), $0.6 million and $2.0 million for the years ended December 31, 2009, 2008 and 2007, respectively.

	Year Ended December 31,		
	2009	2008	2007
	(In thousands)		
Acquisition costs:			
Unproved properties	$ 35,248	$ 271,618	$ 54,467
Proved properties			
Exploration costs	77,255	235,382	144,402
Development costs	55,270	49,626	30,562
Asset retirement obligation	(1,390)	630	1,961
Total costs incurred	$ 166,383	$ 557,256	$ 231,392
Total proved reserves added (MMcfe)	132,326	180,594	155,139
Average all-sources finding cost (per Mcfe)	$ 1.26	$ 3.09	$ 1.49
Average finding and development cost (per Mcfe)[1]	$ 1.16	$ 1.68	$ 1.22
Average drilling finding cost (per Mcfe)	$ 0.99	$ 1.58	$ 1.14

(1) 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, 2009, our total cost for exploration, development and acquisition activities was approximately $958.5 million. Total exploration, development and acquisition activities for the three year period ended December 31, 2009 have added approximately 468.1 Bcfe of net proved reserves at an all-sources finding cost of $2.05 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 $(12.3) million, $47.6 million, and $75.7 million at December 31, 2009, 2008 and 2007, respectively, and includes total additions to proved undeveloped reserves of 28.7 Bcfe, 53.3 Bcfe and 59.6 Bcfe for the years ended December 31, 2009, 2008 and 2007, respectively. Accordingly, had we included future development costs in our computations, the average all-sources finding costs would have been $1.19,

$3.35 and $1.98 per Mcfe for the years ended December 31, 2009, 2008 and 2007, respectively. Year on year, future development costs declined in 2009 by approximately $12.3 million net, largely comprised of (1) a $41.7 million decline in the Camp Hill Field future development costs attributable to a 30.1 Bcfe decrease in proved undeveloped reserves due to the five year development plan limitation under the new Commission rules, partially offset by (2) a $22.8 million net increase in the Barnett Shale future development costs comprised of (a) an approximate $146.6 million increase in future development costs associated with the additions to proved developed non-producing and proved undeveloped reserves and by (b) a net $84.5 million decrease in future development costs due to realized reductions in actual costs to drill and complete the wells compared to the prior year and (c) a net $39.3 million reduction from proved developed non-producing and proved undeveloped wells which no longer met Commission guidelines for economic or other reasons.

In order to maintain continued growth and achieve profitability, 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 natural 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.

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Drilling Activity

The following table sets forth our drilling activity for the years ended December 31, 2009, 2008 and 2007 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,					
	2009		2008		2007	
	Gross	Net	Gross	Net	Gross	Net
Exploratory Wells Productive						
United States	46	22.4	83	60.0	64	42.6
U.K. North Sea			1	0.2	1	0.2
Total	46	22.4	84	60.2	65	42.8
Exploratory Wells Nonproductive						
United States	1	0.8	2	0.3	1	0.4
U.K. North Sea					1	0.2
Total	1	0.8	2	0.3	2	0.6
Development Wells Productive						
United States	16	13.0	31	24.2	29	24.0
U.K. North Sea						
Total	16	13.0	31	24.2	29	24.0
Development Wells Nonproductive						
United States			3	3.0	1	1.0
U.K. North Sea						
Total			3	3.0	1	1.0

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

As of December 31, 2009, we are in the process of drilling four gross wells (3.0 net) in the United States and no wells in the U.K. North Sea.

Productive Wells

The following table sets forth the number of productive oil and natural gas wells in which we owned an interest as of December 31, 2009.

	Company Operated		Non-Operated		Total	
	Gross	Net	Gross	Net	Gross	Net
Oil	92	86.8	4	0.8	96	87.6
Natural gas	194	165.8	155	35.5	349	201.3
Total	286	252.6	159	36.3	445	288.9

Acreage Data

The following table sets forth certain information regarding our developed and undeveloped lease acreage as of December 31, 2009. Developed acres refer 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.

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	Developed Acreage		Undeveloped Acreage		Total	
	Gross	Net	Gross	Net	Gross	Net
Barnett Shale Texas	36,717	24,679	35,791	27,487	72,508	52,166
Marcellus Shale						
New York			37,067	8,298	37,067	8,298
Pennsylvania			102,172	40,578	102,172	40,578
West Virginia			105,881	50,821	105,881	50,821
Virginia and other			14,390	7,121	14,390	7,121
Marcellus Shale Total			259,510	106,818	259,510	106,818
Other						
Other Shales(1)	919	310	411,164	257,181	412,083	257,491
Texas (2)	31,102	10,950	74,294	54,701	105,396	65,651
Other	2,455	1,383	24,899	13,583	27,354	14,966
Other Total	34,476	12,643	510,357	325,465	544,833	338,108
Total United States	71,193	37,322	805,658	459,770	876,851	497,092
Total U.K. North Sea			275,146	140,346	275,146	140,346
Total	71,193	37,322	1,080,804	600,116	1,151,997	637,438

(1) Other Shales principally includes the 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.

(2) Other Texas includes the Camp Hill Field and other non-resource plays in North, East and Central Texas.

The table does not include 3,725 gross and 1,862 net acres under lease option that we had a right to acquire in Texas and 2,136 gross and 1,068 net acres under lease option that we had a right to acquire in Pennsylvania pursuant to various seismic and lease option agreements at December 31, 2009. Under the terms of our option agreements, we typically have the right for a period of one year, subject to extensions, to exercise our option to lease the acreage at predetermined terms.

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 and the age of the lease). If no production is established on our leases that are in their primary term, approximately 16% of our acreage will expire in 2010, 37% will expire in 2011 and 11% will expire in 2012.

Marketing

Our production is marketed to third parties consistent with industry practices. Typically, our oil and natural gas is sold at the wellhead. Oil is sold at field-posted prices plus a bonus and natural gas is sold under contract at a negotiated price based that is based upon a publicly traded price at a hub 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. In 2009, we made the strategic decision to sell as much of our natural gas production at the wellhead as possible, so that we could 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, sold most of the pipelines that we owned in the Barnett Shale. We also entered into a gas purchase agreement with DTE Energy to purchase our natural gas production throughout most of our operated properties in the Barnett Shale at competitive market prices based on a differential to several sales points in East Texas.

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 Barnett Shale area and the Texas and Louisiana onshore Gulf Coast area.

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

demand for natural gas and oil;

the extent of production of natural gas and oil 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 natural gas and oil production and sales.

See Item 1A. Risk Factors Natural gas and oil prices are highly volatile, and lower prices will negatively affect our financial results, Item 1A. Risk Factors We are subject to various governmental regulations and environmental risks, and Item 1A. Risk Factors 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 natural gas at the wellhead, we work with various pipeline companies 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 future operated Marcellus Shale production in portions of Northern Pennsylvania. We also conduct an active hedging program at the corporate level 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 natural gas and oil 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 natural gas and oil 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 natural gas and oil 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.

The natural gas and oil 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

Natural gas and oil operations are subject to various federal, state, local and international environmental regulations that may change from time to time, including regulations governing natural gas and oil 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 natural gas and oil 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 natural gas and oil, protect rights to produce natural gas and oil between owners in a common reservoir, control the amount of natural gas and oil 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 natural gas and oil properties and the unitization or pooling of natural gas and oil 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 natural gas and oil 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 natural gas and oil 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 natural gas and oil 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 the existing infrastructure. In order to partly alleviate this issue, commencing in 2008, 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 (the Gas Utility Regulatory Act or 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 (RRC) 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 million per day for each violation.

Oil Price Controls and Transportation Rates

Our sales of 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 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 March 2006, to implement the second of the required five-yearly re-determinations, the FERC established an upward adjustment in the index to track oil pipeline cost changes. The FERC determined that the Producer Price Index for Finished Goods plus 1.3 percent (PPI plus 1.3 percent) should be the oil pricing index for the five-year period beginning July 1, 2006. We are not able at this time to predict the effects of 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, particularly in light of the change in the U.S. administration in 2009, or what the ultimate effect on our sales of gas, oil 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 natural gas and oil 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 natural gas and oil 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 natural gas and oil. 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 natural gas and oil 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 governmental regulations and environmental risks.

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 (CAA) and comparable state and local requirements. In 1990 Congress adopted amendments to the CAA 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 (TCEQ) and the Railroad Commission of Texas have been evaluating possible additional regulation of air emissions in the Barnett Shale area, in response to concerns about allegedly high concentrations of benzene in the air near drilling sites and natural gas processing facilities. 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 recently entered into a settlement that requires it to consider strengthening regulations under the CAA, including the New Source Performance Standards, Maximum Achievable Control Technology standards and residual risk standards, affecting a wide array of air emission sources in the oil and gas industry. 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.

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 (SPCC) 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 million in specified state waters to $35 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 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 is currently considering legislation to amend the federal Safe Drinking Water Act to subject hydraulic fracturing operations to regulation under that Act 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 international 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 us.

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

In response to recent studies suggesting that emissions of carbon dioxide and certain other gases may be contributing to warming of the Earth s atmosphere, the U.S. Congress is actively considering legislation to reduce emissions of greenhouse gases (GHGs) from sources within the United States between 2012 and 2050. For example, the 110th session of Congress considered various bills that proposed a cap and trade scheme of regulation of greenhouse gas emissions that generally would ban emissions above a defined reducing annual cap. Covered parties would be authorized to emit greenhouse emissions through the acquisition and subsequent surrender of emission allowances that may be traded or acquired on the open market. In addition, at least 17 states have already taken legal measures to reduce emissions of GHGs, primarily through the planned development of greenhouse gas emission inventories and/or regional greenhouse gas cap and trade programs. Most of these cap and trade programs require either major sources of emissions, such as electric power plants, or major producers of fuels, such as refineries or gas processing plants, to acquire and surrender emission allowances. The number of allowances available for purchase is reduced each year until the overall greenhouse gas emission reduction goal is achieved.

Depending on the particular program, we could be required to purchase and surrender allowances, either for greenhouse gas emissions resulting from our operations or from combustion of oil or natural gas we produce. Although we would not be impacted to a greater degree than other similarly situated producers of oil and gas, a stringent greenhouse gas control program could have an adverse effect on our cost of doing business and could reduce demand for the oil and gas we produce.

Also, in the wake of the U.S. Supreme Court s decision in April 2007 in *Massachusetts v. Environmental Protection Agency*, the EPA has begun to regulate carbon dioxide and other greenhouse gas emissions, even though Congress has yet to adopt new legislation specifically addressing emissions of GHGs. In late 2009, the EPA issued a Mandatory Reporting of Greenhouse Gases final rule, which establishes a new comprehensive regulation and reporting scheme for operators of stationary sources emitting certain levels of GHGs, and a Final Rule finding that certain current and projected GHGs in the atmosphere threaten public health and welfare of current and future generations. Please read Item 1A. Risk Factors Climate change and climate change legislation and regulatory initiatives could result in increased operating costs and decreased 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 natural gas and oil 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 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 natural gas and oil 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 make little investigation 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 senior credit facility is secured by substantially all of our natural gas and oil properties.

In acquiring producing properties, we assess the recoverable reserves, future natural gas and oil 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 condition and future results of operations. See Item 1A. Risk Factors Our future acquisitions may yield revenues or production that varies significantly from our projections.

Customers

The Company sold oil and natural gas production representing at least 10% of its oil and natural gas revenues as follows:

	Year Ended December 31,		
	2009	**2008**	**2007**
DTE Energy Trading, Inc.	54%	39%	*
Cokinos Natural Gas Company	*	11%	11%
Crosstex Energy	*	10%	15%
Houston Pipeline Company	*	*	11%
Energy Transfer	*	*	10%

* Revenues were below 10%.

Because alternative purchasers of oil and natural gas are readily available, we believe that the loss of any of our purchasers would not have a material adverse effect on our financial results.

Employees

At December 31, 2009, we had 111 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.

We depend to a large extent on the services of certain key management personnel and the loss of any could have a material adverse effect on our operations. We do not maintain key-man life insurance with respect to any of our employees.

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 this website, through a direct link to the Commission s website at www.sec.gov, free of charge, our annual reports 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 those materials. You may read and copy any materials we file with the Commission at the Commission 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 Commission 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 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 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.

Item 1A. Risk Factors

The global financial and credit crisis may have impacts on our liquidity and financial condition that we currently cannot predict.

The recent credit crisis and continued 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 natural gas and oil derivatives transactions 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 natural gas and oil, or further reductions in the prices of natural gas and oil, 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 condition.

Natural gas and oil prices are highly volatile and have declined significantly since mid-2008, and lower prices will negatively affect our financial condition, planned capital expenditures and results of operations.

Since July 2008, publicly quoted spot natural gas and oil prices have declined significantly from 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 natural gas and oil 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. The decrease in natural gas prices has had a significant impact on our financial condition, planned capital expenditures and results of operations. Further volatility in natural gas and oil prices or a prolonged period of low natural gas and oil prices may materially adversely affect our financial condition, liquidity (including our borrowing capacity under our senior 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 natural gas and oil. Historically, the markets for natural gas and oil prices have been volatile, and those markets are likely to continue to be volatile in the future. It is impossible to predict future natural gas and oil price movements with certainty. Prices for natural gas and oil are subject to wide fluctuation in response to relatively minor changes in the supply of and demand for natural gas and oil, market uncertainty and a variety of additional factors beyond our control. These factors include:

- the level of consumer product demand;
- overall economic conditions;
- weather conditions;
- domestic and foreign governmental relations, regulations and taxes;
- the price and availability of alternative fuels;
- political conditions;
- 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.

Natural gas and oil 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 natural gas and oil involves numerous risks, including the risk that no commercially productive natural gas or oil 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 the onshore Gulf Coast area 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 natural gas or oil 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 condition by reducing our available cash and resources. 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 natural gas and oil 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.

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 natural gas and oil reserves and their estimated value, including many factors beyond the control of the producer. The reserve data set forth in this Annual Report on Form 10-K represent only estimates. Reservoir engineering is a subjective and inexact process of estimating underground accumulations of natural gas and oil 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 Commission adopted new rules regarding the classification of reserves. These new rules became effective with the reserves reported in this Annual Report on Form 10-K. However, the interpretation of these rules and their applicability in different situations remains 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, 2009, approximately 55% 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, 2009 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.

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The discounted future net cash flows presented in this Annual Report Form 10-K are not necessarily the same as the current market value of our estimated natural gas and oil reserves. As required by the Commission, the estimated discounted future net cash flows from proved reserves are currently 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 natural gas and oil;
- our actual operating costs in producing natural gas and oil;
- the amount and timing of actual production;
- supply and demand for natural gas and oil;
- increases or decreases in consumption of natural gas and oil; 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 Statement of Financial Accounting Standards No. 69 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 natural gas and oil 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 natural gas and oil 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 natural gas and oil 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 natural 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 natural 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 natural gas and oil 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 condition.

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 senior credit facility or new credit facilities may not be available in the future. The credit crisis that began in late 2008 has had an adverse impact on our ability to obtain additional financing. 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 natural gas and oil 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 natural gas and oil properties, in turn negatively affecting our business, financial condition and results of operations.

Our senior credit facility contains operating restrictions and financial covenants, and we may have difficulty obtaining additional credit.

Over the past few years, increases in commodity prices and our successful drilling program led to increased proved reserve amounts, and the resulting increase in our estimated discounted future net revenue allowed us to increase the borrowing base under our senior credit facility. However, as a result of the significant decline in natural gas and oil prices, or other factors, the lenders under our senior credit facility may adjust our borrowing base downward, thereby reducing our borrowing capacity. Our senior credit facility is secured by a pledge of substantially all of our producing natural gas and oil properties and assets, guaranteed by our subsidiaries CCBM, Inc., CLLR, Inc., Hondo Pipeline, Inc., Carrizo (Marcellus) LLC, Carrizo Marcellus Holding Inc., Bandelier Pipeline Holding, LLC and Mescalero Pipeline, LLC and contains covenants that limit additional borrowings, dividends, the incurrence of liens, investments, sales or pledges of assets, changes in control, repurchases or redemptions for cash of our common stock, speculative commodity transactions and other matters. The senior credit facility also requires that specified financial ratios be maintained. Although we currently believe that we can meet all of our financial covenants with the business plan that we have put in place, our business plan is based on a number of assumptions, the most important of which is a relatively stable natural gas price at economically sustainable levels. If the price that we receive for our 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 senior credit facility, including the covenants related to working capital, the ratio of EBITDA to debt coverage and the ratio of senior debt to EBITDA. In order to provide a further margin of comfort with regards to these financial covenants, we may seek to further reduce our capital and exploration plan, sell additional non-strategic assets or opportunistically modify or increase our natural gas hedges. There can be no assurance 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 senior credit facility if a precipitous decline in natural gas prices were to occur in the future. We may not be able to refinance our debt or obtain additional financing, particularly in view of the restrictions of our senior credit facility on our ability to incur additional debt and the fact that substantially all of our assets are currently pledged to secure obligations under the senior credit facility. The restrictions of our senior credit facility and our difficulty in obtaining additional debt financing may have adverse consequences on our operations and financial results including:

- our ability to obtain financing for working capital, capital expenditures, our drilling program, purchases of new technology or other purposes may be impaired;
- the covenants in our senior credit facility that limit our ability to borrow additional funds and dispose of assets may affect our flexibility in planning for, and reacting to, changes in business conditions;
- because our indebtedness is subject to variable interest rates, we are vulnerable to increases in interest rates;
- any additional financing we obtain may be on unfavorable terms;
- we may be required 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;
- a substantial decrease in our operating cash flow or an increase in our expenses could make it difficult for us to meet debt service requirements and could require 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; and
- we may become more vulnerable to downturns in our business or the economy.

In addition, under the terms of our senior credit facility, our borrowing base is subject to redeterminations at least semi-annually based in part on prevailing natural gas and oil prices. Although we do not know at this time whether the borrowing base will be adjusted upwards or downwards in the future, a negative adjustment could occur if the estimate of future prices used by the banks in calculating the borrowing base are significantly lower than those used in the last redetermination. In the event the amount outstanding under our senior 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.

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 during the last five 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, 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 condition timely and accurately and cause us to fail to meet our reporting obligations under rules of the Commission and NASDAQ and our various debt arrangements.

We have limited experience drilling wells in the Marcellus Shale and less information regarding reserves and decline rates in the Marcellus Shale than in 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 experience and no development experience in the Marcellus Shale. As of December 31, 2009, we have participated or are participating in the drilling of only 11 wells in the Marcellus Shale area, none of which are horizontal wells. 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 other areas in which we operate. Moreover, the recent growth in exploration in the Marcellus Shale has drawn intense scrutiny from environmental interest groups, regulatory agencies and other governmental entities. As a result, we may face significant opposition to our operations that may make it difficult or impossible to obtain permits and other needed authorizations to operate or otherwise make operating more costly or difficult than operating elsewhere.

If we are unable to acquire adequate supplies of water for our Marcellus Shale 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 Marcellus Shale drilling operations. Our inability to locate sufficient amounts of water, or dispose of water after drilling, could adversely impact our Marcellus Shale 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, new environmental regulations and permit requirements governing the withdrawal, storage and use of surface water or groundwater necessary for hydraulic fracturing of wells may also 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 affect on our operations and financial performance.

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

Our primary core producing area is located in largely urban portions of the Barnett Shale region, which could disproportionately expose us to operational and regulatory risk in that area. At December 31, 2009, approximately 97% of our proved reserves and approximately 80% of our then current production were located in the Barnett Shale. The core of the Barnett Shale formation 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 natural gas and oil companies.

We encounter competition from other natural gas and oil companies in all areas of our operations, including the acquisition of exploratory prospects and proven properties. Our competitors include major integrated natural gas and oil companies and numerous independent natural gas and oil companies, individuals and drilling and income programs. Many of our competitors are large, well-established companies that have been engaged in the natural gas and oil 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 natural gas and oil 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 natural gas and oil 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 natural gas and oil 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.

Natural gas and oil operations are subject to various federal, state, local and foreign 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 natural gas and oil wells below actual production capacity in order to conserve supplies of natural gas and oil. Other federal, state and local 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 natural gas and oil, by-products thereof and other substances and materials produced or used in connection with natural gas and oil operations. In addition, we may be liable for environmental damages caused by previous owners of property we purchase or lease. 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 have a material adverse effect on our business, financial condition and results of operations.

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 (TCEQ) and the Railroad Commission of Texas have been evaluating possible additional regulation of air emissions in the Barnett Shale area, in response to concerns about allegedly high concentrations of benzene in the air near drilling sites and natural gas processing facilities. 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 recently entered into a settlement that requires it to consider strengthening regulations under the Clean Air Act (CAA), including the New Source Performance Standards (NSPS), maximum achievable control technology standards (MACT) and residual risk standards, affecting a wide array of air emission sources in the oil and gas industry. 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.

Similarly, the U.S. Congress is currently considering legislation to amend the federal Safe Drinking Water Act to subject hydraulic fracturing operations to regulation under that Act and to require the disclosure of chemicals used by us and others in the oil and gas industry in the hydraulic fracturing process. 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 and Marcellus Shale. Hydraulic fracturing involves the injection of water, sand and chemicals under pressure into rock formations to stimulate gas production. Sponsors of bills currently pending before the U.S. Senate and House of Representatives have asserted that chemicals used in the fracturing process could adversely affect drinking water supplies. Proposed legislation would require, among other things, the reporting and public disclosure of chemicals used in the fracturing process, which could make it easier for third parties opposing the hydraulic fracturing process to initiate legal proceedings against producers and service providers. In addition, these bills, if adopted, could establish an additional level of regulation and permitting of hydraulic fracturing operations at the federal level, which could lead to operational delays, increased operating costs and additional regulatory burdens that could make it more difficult for us to perform hydraulic fracturing. We use hydraulic fracturing extensively and any increased federal, state or local regulation, including proposed legislation in the state of New York, could reduce the volumes of natural gas that we can economically recover, which could materially and adversely affect our revenues and results of operations.

President Obama s Proposed 2011 Fiscal Year Budget includes proposed legislation that would, if enacted into law, 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 natural gas exploration and production companies. The passage of any legislation as a result of these proposals 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 condition 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 concerning the issue of climate change and the effect of greenhouse gases (GHG). On September 22, 2009, the EPA issued a Mandatory Reporting of Greenhouse Gases final rule (Reporting Rule). The Reporting Rule establishes a new comprehensive scheme requiring operators of stationary sources emitting more than established annual thresholds of carbon dioxide-equivalent GHGs to inventory and report their GHG emissions annually on a facility-by-facility basis. In addition, on December 15, 2009, the EPA published a Final Rule finding that current and projected concentrations of six key GHGs in the atmosphere threaten public health and the welfare of current and future generations. The EPA also found that the combined emissions of these GHGs from new motor vehicles and new motor vehicle engines contribute to pollution that threatens public health and welfare. This Final Rule, also known as the EPA s Endangerment Finding, does not impose any requirements on industry or other entities directly. However, the EPA must now finalize motor vehicle GHG standards, the effect of which could reduce demand for motor fuels refined from crude oil. Finally, according to the EPA, the final motor vehicle GHG standards will trigger construction and operating permit requirements for stationary sources. 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 currently underway to develop a treaty to replace the Kyoto Protocol after its expiration in 2012. 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 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.

Moreover, some experts believe climate change poses potential physical risks, including an increase in sea level and changes in weather conditions, such as an increase in changes in precipitation and extreme weather events. To the extent that such unfavorable weather conditions are exacerbated by global climate change or otherwise, our operations may be adversely affected to a greater degree than we have previously experienced, including increased delays and costs. However, the uncertain nature of changes in extreme weather events (such as increased frequency, duration, and severity) and the long period of time over which any changes would take place make estimating any future financial risk to our operations caused by these potential physical risks of climate change extremely challenging. In accordance with customary industry practices, we maintain insurance against some, but not all, of these risks.

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

The natural gas and oil business involves operating hazards such as:

well blowouts;
mechanical failures;

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- explosions;
- uncontrollable flows of oil, natural gas or well fluids;
- fires;
- geologic formations with abnormal pressures;
- 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, such as capsizing, collisions and damage or loss from hurricanes or other adverse weather conditions. 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. Any significant change affecting these infrastructure facilities could materially harm our business. We deliver crude oil and natural gas through gathering systems and pipelines that we do not own. These facilities may be temporarily unavailable due to adverse weather conditions 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.

A substantial 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.

Losses could occur for uninsured risks or in amounts in excess of existing insurance coverage. 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. An event that is not fully covered by insurance could have a material adverse effect on our financial position and results of 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, we cannot insure fully against pollution and environmental risks. 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 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 natural gas and/or receive market prices for our natural gas may be adversely affected by pipeline and gathering system capacity constraints.

Market conditions or the unavailability of satisfactory oil and natural gas transportation arrangements may hinder our access to oil and natural gas markets or delay our production. The availability of a ready market for our oil and natural gas production depends on a number of factors, including the demand for and supply of oil and natural 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 natural gas may have several adverse affects, 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 and, to a lesser extent, the Barnett Shale.

Historically, we have generally delivered natural gas through gas gathering systems and gas pipelines that we do not own under interruptible or short-term transportation agreements. Under the interruptible transportation agreements, the transportation of our gas 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 Barnett Shale, we have entered into firm transportation agreements in the Barnett Shale and are contemplating doing so in the Marcellus Shale, in order to assure our ability, and that of our purchasers, to successfully market the gas that we produce. These firm transportation agreements are 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 natural gas and oil 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 natural gas and oil 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 condition 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 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 condition 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 condition 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 natural gas and oil.

Because natural gas and oil prices are unstable, we periodically enter into price-risk-management transactions such as swaps, collars, futures and options to reduce our exposure to price declines associated with a portion of our natural gas and oil 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 natural gas and oil. Our derivative arrangements may apply to only a portion of our production, thereby providing only partial protection against declines in natural gas and oil 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 natural gas and oil or a sudden, unexpected event materially impacts natural gas or oil 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 natural gas properties.

During periods when natural gas and oil prices are relatively high, which was recently the case until mid 2008, 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 ceiling limitation write-downs that would reduce our shareholders equity.

We use the full-cost method of accounting for investments in natural gas and oil properties. Accordingly, we capitalize all the direct costs of acquiring, exploring for and developing natural gas and oil properties. Under the full-cost accounting rules, the net capitalized cost of natural gas and oil properties may not exceed a ceiling limit that is based on the present value of estimated future net revenues from proved reserves, discounted at 10%, plus the lower of the cost or the fair market value of unproved properties. If net capitalized costs of natural gas and oil properties exceed the ceiling limit, we must charge the amount of the excess to operations through depreciation, depletion and amortization expense. This charge is called a ceiling limitation write-down. This charge does not impact cash flow from operating activities but does reduce our shareholders equity. The risk that we will be required to write down the carrying value of our natural gas and oil properties increases when natural gas and oil prices are low or volatile. In addition, write-downs 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. Once incurred, a write-down of natural gas and oil properties is not reversible at a later date. We recorded non-cash ceiling test limitation write-downs at the end of 2008, the end of the first quarter of 2009 and the end of 2009. We could incur additional write-downs in the future, particularly as a result of a decline of natural gas and oil prices.

We could lose our ability to use NOLs that we have accumulated over the years.

Our ability to utilize NOL carryfowards to reduce future taxable income is subject to various limitations under the Internal Revenue Code of 1986, as amended. The utilization of such carryfowards 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, 2009, we believe an ownership change occurred in February 2005 with an annual limitation of approximately $12.5 million. 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 NOL carryforwards as of December 31, 2009. Future equity transactions involving the Company or 5% shareholders of the Company (including, potentially, relatively small transactions and transactions beyond our control) could cause further ownership changes and therefore a limitation on the annual utilization of NOLs.

Enactment of a Pennsylvania severance tax on natural gas could adversely impact our results of operations and the economic viability of exploiting natural gas drilling and production opportunities in Pennsylvania.

As a result of a funding gap in the state budget, the governor of the Commonwealth of Pennsylvania has proposed to its legislature the adoption of a severance tax on the production of natural gas in Pennsylvania. The amount of the proposed tax is 5% of the value of the natural gas at wellhead, plus 4.7 cents per 1,000 cubic feet of natural gas severed. A substantial portion of our Marcellus Shale acreage is located in the Commonwealth of Pennsylvania. If Pennsylvania adopts such a severance tax, it could adversely impact our results of operations and the economic viability of exploiting natural gas drilling and production opportunities in Pennsylvania. If adopted by the legislature, the governor currently proposes that this law would become effective in 2010.

We may incur losses as a result of title deficiencies.

We purchase working and revenue interests in the natural gas and oil 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 natural gas and oil 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 natural gas and oil 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.

The threat and impact of terrorist 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 or war.

Item 1B. Unresolved Staff Comments

None.

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 major multiple.

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 or Barrel of Oil Equivalent. 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.

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

Completion. The process of treating a drilled well followed by the installation of permanent equipment for the production of natural gas or oil, or in the case of a dry 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 a natural gas or oil 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 natural gas or oil in sufficient quantities to justify completion as a natural gas or oil 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.

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

Farm-in or farm-out. An agreement where under the owner of a working interest in an oil and natural 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.

Fracing. Fracing is the process of hydraulic fracture stimulation using a liquid (usually water) 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. Fracing is an essential technology in shale reservoirs and other unconventional resource plays where nearly all wells are frac d in order to produce commercial hydrocarbon production.

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 natural gas reserves which are capitalized by us pursuant to generally accepted accounting principles, 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.

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.

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

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. 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.

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 natural 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 Commission 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 natural gas or oil in sufficient quantities to justify completion as a natural gas or oil 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. The present value of estimated future revenues to be generated from the production of proved reserves calculated in accordance with Commission guidelines, net of estimated production and future development costs, using prices and costs as of the date of estimation without future escalation, without giving effect to non-property related expenses such as general and administrative expenses, debt service, future income tax expense and depreciation, depletion and amortization, and 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 natural gas property entitling the owner to a share of oil or natural 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 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. Reserved

Executive Officers of the Registrant

Pursuant to Instruction 3 to Item 401(b) of Regulation S-K and General Instruction G(3) to Form 10-K, the following information is included in Part I of this Form 10-K.

The following table sets forth certain information with respect to our executive officers

Name	Age	Position
S.P. Johnson IV	54	President, Chief Executive Officer and Director
Paul F. Boling	56	Chief Financial Officer, Vice President, Secretary and Treasurer
David L. Pitts	43	Vice President and Chief Accounting Officer
J. Bradley Fisher	49	Vice President and Chief Operating Officer
Gregory E. Evans	60	Vice President of Exploration
Richard H. Smith	52	Vice President of Land

Set forth below is a description of the backgrounds of each of our executive officers.

S.P. Johnson IV has served as our President and Chief Executive Officer and a director since December 1993. Prior to that, he worked for Shell Oil Company for 15 years. His managerial positions included Operations Superintendent, Manager of Planning and Finance and Manager of Development Engineering. Mr. Johnson is also a director of Basic Energy Services, Inc. (a well servicing contractor) and Pinnacle Gas Resources, Inc. (a coalbed methane production company). Mr. Johnson is a Registered Petroleum Engineer and has a B.S. in Mechanical Engineering from the University of Colorado.

Paul F. Boling has served as our Chief Financial Officer, Vice President, Secretary and Treasurer since August 2003. From 2001 to 2003, Mr. Boling was the Global Controller for Resolution Performance Products, LLC, an international epoxy resins manufacturer. From 1990 to 2001, Mr. Boling served in a number of financial and managerial positions with Cabot Oil & Gas Corporation, serving most recently as Vice President, Finance. Mr. Boling is a CPA and holds a B.B.A. from Baylor University.

David L. Pitts has served as Vice President and Chief Accounting Officer since January 2010. Prior to that time, he served as an audit partner with Ernst & Young. Prior to his employment at Ernst &Young from 2002 to 2009, David was a senior manager with Arthur Andersen. Mr. Pitts is a CPA and holds a B.S. from Southwest Baptist University.

J. Bradley Fisher has served as Vice President and Chief Operating Officer since March 2005. Prior to that time, he served as Vice President of Operations since July 2000 and General Manager of Operations from April 1998 to June 2000. Prior to joining us, Mr. Fisher was the Vice President of Engineering and Operations for Tri-Union Development Corp. from August 1997 to April 1998. He spent the prior 14 years with Cody Energy and its predecessor Ultramar Oil & Gas Limited where he held various managerial and technical positions, last serving as Senior Vice President of Engineering and Operations. Mr. Fisher holds a B.S. degree in Petroleum Engineering from Texas A&M University.

Gregory E. Evans has served as Vice President of Exploration since March 2005. Prior to joining us, Mr. Evans was Vice President North America Onshore Exploration for Ocean Energy from 2001 to 2003. Prior to that time, he spent 19 years at Burlington Resources where he served as Chief Geophysicist North America during 1999 to 2000, Gulf of Mexico Deep Water Exploration Manager during 1998 to 1999 and Geoscience Manager for the Western Gulf of Mexico Shelf during 1996 to 1998. From 1982 to 1996, Mr. Evans held various other technical and managerial positions with Burlington Resources, including Division Exploration Manager of both the Rocky Mountain Region as well as the Gulf Coast area. Mr. Evans received a B.S. in Geophysical Engineering from the Colorado School of Mines receiving the Cecil H. Green award for outstanding geophysical student.

Richard H. Smith has served as Vice President of Land since August 2006. Prior to joining us, Mr. Smith held the position of Vice President of Land for Petrohawk Energy Corporation from March 2004 through August 2006. Mr. Smith served with Unocal Corporation from April 2001 until March 2004 where he held the position of Land Manager Gulf Region USA with areas of concentration in the OCS, Onshore Texas and Louisiana and Louisiana State Waters. From September 1997 until March 2001 Mr. Smith held the position of Land Manager Gulf Coast Region with Basin Exploration, Inc. Mr. Smith held various land management positions with Sonat Exploration Company, Michel T. Halbouty Energy Co., Pend Oreille Oil & Gas Company and Norcen Explorer, Inc. from the time he began his career in 1980 until the time he joined Basin Exploration. Mr. Smith is a Certified Professional Landman with a B.B.A. in Petroleum Land Management from the University of Texas at Austin.

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
2009		
First Quarter	$21.19	$ 6.71
Second Quarter	23.21	8.42
Third Quarter	26.85	14.75
Fourth Quarter	30.22	20.20
2008		
First Quarter	$62.47	$43.11
Second Quarter	76.30	58.26
Third Quarter	69.51	30.75
Fourth Quarter	36.26	11.72

The closing market price of our common stock on March 10, 2010 was $25.00 per share. As of March 10, 2010, there were an estimated 147 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 senior 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 the Common Stock over the period from December 31, 2004 to December 31, 2009, 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, 2004 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.

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The graph is presented in accordance with requirements of the Commission. 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, 2004	100	100	100
December 31, 2005	103	153	219
December 31, 2006	117	170	257
December 31, 2007	121	217	485
December 31, 2008	75	111	142
December 31, 2009	92	154	235

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

The Company made no repurchases of its common stock in the fourth quarter of 2009.

As described in Item 7. Management s Discussion and Analysis of Financial Condition and Results of Operations Liquidity and Capital Resources, we have issued, and may issue, warrants and common stock under the 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, for transactions not involving a public offering.

Item 6. Selected Financial Data

Our financial information set forth below for each of the five years in the period ended December 31, 2009, has been derived from our audited consolidated financial statements. The information should be read in conjunction with such section and our consolidated financial statements and related notes included in Item 8. Financial Statements and Supplementary Data.

	Year Ended December 31,				
	2009	2008	2007	2006	2005
	(In thousands, except per share data)				
Statements of Operations Data:					
Oil and natural gas revenues	$ 114,079	$ 216,677	$ 125,789	$ 82,945	$ 78,155
Costs and expenses:					
Oil and natural gas operating expenses	30,204	37,885	24,662	16,428	10,437
Impairment of oil and natural gas properties	338,914	178,470			
Depreciation, depletion and amortization	52,005	58,311	41,899	31,129	21,374
Third party gas purchases	1,497	6,570			
General and administrative	30,136	23,425	18,912	14,909	11,243
Accretion expense related to asset retirement obligation	308	154	374	496	70
Total costs and expenses	453,064	304,815	85,847	62,962	43,124
Operating income (loss)	(338,985)	(88,138)	39,942	19,983	35,031
Gain (loss) on derivatives, net	41,465	37,499	(1,366)	16,457	(5,882)
Loss on extinguishment of debt		(5,689)		(294)	(3,721)
Equity in income (loss/impairment) of Pinnacle Gas Resources, Inc.	(2,091)			35	(2,542)
Interest expense, net of amounts capitalized and interest income	(18,577)	(9,461)	(13,994)	(8,127)	(4,295)
Other income, net	36	17	130	427	(457)
Income (loss) before income tax expense (benefit)	(318,152)	(65,772)	24,712	28,481	18,134
Income tax expense (benefit)	(113,307)	(20,725)	9,243	10,233	7,500
Net income (loss) available to common shareholders	$ (204,845)	$ (45,047)	$ 15,469	$ 18,248	$ 10,634
Basic earnings (loss) per common share	$ (6.61)	$ (1.49)	$ 0.58	$ 0.73	$ 0.45
Diluted earnings (loss) per common share	$ (6.61)	$ (1.49)	$ 0.57	$ 0.71	$ 0.44
	31,006	30,326	26,641	25,081	23,539

Basic weighted average shares outstanding					
Diluted weighted average shares outstanding	31,006	30,326	27,120	25,565	24,361
Statements of Cash Flow Data:					
Net cash provided by operating activities	$ 133,372	$ 148,754	$ 95,231	$ 65,437	$ 38,839
Net cash used in investing activities	(162,453)	(555,345)	(227,724)	(161,576)	(111,417)
Net cash provided by financing activities	27,734	403,749	135,111	72,822	95,635
Other Cash Flow Data:					
Capital expenditures	$ 182,907	$ 571,291	$ 247,003	$ 201,773	$ 135,156
Debt repayments[(1)]	96,461	498,923	108,258	40,536	101,021
Balance Sheet Data:					
Working capital (deficit)	$ (47,328)	$ (57,602)	$ (50,053)	$ (17,014)	$ 10,307
Property and equipment, net	733,700	986,629	646,810	445,447	314,074
Total assets	863,107	1,071,702	708,663	494,795	383,101
Total debt, net of debt discount	520,336	475,961	254,501	188,758	149,294
Total shareholders equity	247,609	440,085	310,721	212,274	155,385

(1) Debt repayments include amounts refinanced.

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

General Overview

In 2009, we recognized revenues from oil and natural gas production of $112.7 million, record production of 33.0 Bcfe and a record level of oil and gas proved reserves, at December 31, 2009, of 601.9 Bcfe. The key drivers to our success for 2009 included the following:

Drilling program. Our success is largely dependent on the results of our drilling program. During the year ended December 31, 2009, we drilled 63 gross wells (36.2 net wells) with an apparent success rate of 94% that was comprised of: (a) 47 of 47 gross wells (32.7 net wells) in the Barnett Shale area, (b) one of two gross wells (0.25 of 1.0 net well) in the onshore Gulf Coast area, (c) seven gross wells (2.3 net wells) in the Marcellus Shale area, of which three gross (1.5 net) wells awaited testing, and (d) seven of seven gross wells (0.2 net wells) in other areas. At December 31, 2009, 35 of these gross wells (23.5 net wells) were awaiting completion or pipeline connections.

Reserve growth. As a result of our drilling program discussed above, our reserves increased 20% to 601.9 Bcfe at December 31, 2009, replacing 400% of 2009 production.

Production. Our 2009 annual production of 33.0 Bcfe, or 90.5 MMcfe/d, was a record high. The 2009 production increased 28.9% from 2008 production of 25.6 Bcfe. The increase was primarily due to the addition of new Barnett Shale wells.

Commodity prices. Our average natural gas price during 2009 was $3.20 per Mcf (excluding the impact of our hedges), $4.60 per Mcf lower than the 2008 price of $7.80. Our average oil price in 2009 was $58.85 per Bbl, or $40.89 lower than in 2008. 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, particularly natural gas prices, which are beyond our control and have been and are expected to remain volatile.

Financial flexibility. In April 2009, we improved our financial flexibility through an amendment to our senior secured revolving credit facility (the Senior Credit Facility) that (a) increased the maximum total debt leverage ratio under the Senior Credit Facility through 2010 to as high as 4.75 to 1, (b) refined the definition of Net Debt in the leverage ratio to exclude a portion of our 4.375% Senior Convertible Notes due 2028 (the Senior Convertible Notes) ($51 million in 2009 and $39 million in 2010) and (c) added a senior debt leverage covenant with a maximum ratio of 2.25 to 1. During December 2009 the borrowing base and total commitments under the Senior Credit Facility were both increased to $350 million. See Senior Credit Facility for more information. In October 2009, we sold certain of our pipeline gathering systems in the Barnett Shale for approximately $34.7 million. The net proceeds from the sale of this pipeline system were used to reduce the debt outstanding under the Senior Credit Facility. See Recent Events Mansfield Pipeline Sale.

Recent Events

Mansfield Pipeline Sale

We sold our Mansfield pipeline and gathering system in the Barnett Shale play to Delphi Midstream Partners, LLC (Delphi) for net proceeds of $34.7 million. Net proceeds from the sale were used to reduce the debt outstanding under the Senior Credit Facility. We constructed the Mansfield pipeline system to gather and transport natural gas from our Southeast Tarrant County operating area. The pipeline consists of 19 miles of 6, 8 and 10 inch diameter pipe with a current maximum capacity of 70 MMcf/day. The system also includes an associated compression/dehydration facility that was included in the transaction. Over the 30 days preceding the date of sale, the pipeline transported an average of 58 MMcf/day. We have also entered into an agreement to continue to operate the Mansfield pipeline system on Delphi s behalf.

Northeast Pennsylvania Alliance

We have entered into an alliance with Delphi through which the parties have agreed to cooperate in solving gathering and mid-stream pipeline related issues for our Marcellus production in certain Northeast Pennsylvania counties including, among others, Bradford, Susquehanna, Tioga, Wayne and Wyoming counties. We have granted Delphi a right of first offer with respect to these Northeast Pennsylvania counties if we seek a third party to develop and construct a gathering or intrastate pipeline and a right of first refusal with respect to Wyoming County, Pennsylvania if a third party other than Delphi makes a development proposal. This alliance will terminate on the earlier to occur of October 19, 2014 and the first date on which Delphi has invested an aggregate of $100 million to develop and construct pipelines under the alliance. Delphi s funding obligations are subject to certain conditions, including the approval of its board of directors. No projects have yet been constructed under this alliance.

Sumitomo Joint Venture

In December 2009, we entered into a strategic alliance with a subsidiary of Sumitomo Corporation (Sumitomo). We sold Sumitomo a 12.5% working interest in 16 of our drilling units in the Barnett Shale for $15.7 million for certain costs previously incurred by us with respect to these drilling units, including Sumitomo s proportionate share of certain land seismic and drilling costs. As part of our agreement, Sumitomo undertook an obligation to fund the drilling and completion of 30 wells on a promoted basis and received an option to participate in up to an additional 56 future wells on a similar promoted basis. We currently expect Sumitomo will exercise its option to participate in the additional 56 wells. Additional wells may be drilled under the joint venture within these units but would be drilled on an unpromoted basis. The net proceeds from this sale were used to reduce the debt outstanding under the Senior Credit Facility.

Outlook for 2010

Our outlook for 2010 is challenging, primarily as a result of the decline in natural gas and oil prices that began in mid 2008, but our outlook for the long-term future remains positive. 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 have a positive impact on our results in 2010:

Control capital costs and maintain financial flexibility. In response to reduced demand for natural gas and lower natural gas prices as a result of the continued economic downturn, we have set our capital expenditure plan for 2010 at $170 million, and we are striving to maintain our financial flexibility and a positive production growth profile. A deterioration in commodity prices may cause us to reduce our capital and exploration plan for 2010.

2010 drilling and capital program. In 2010 we plan to drill 57 gross (38.1 net) wells in the Barnett Shale area, 11 gross (3.8 net) wells in the Marcellus Shale area, and three gross (1.5 net) wells in our other areas. As mentioned above, our 2010 capital expenditure plan has been set at $170 million and includes approximately $130 million drilling in the Barnett Shale and $15 million for drilling in the Marcellus Shale, and $25 million for lease and seismic acquisition activities and drilling and development in other project areas. The actual number of wells we drill will 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 and other factors.

Results of Operations

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

Revenues from oil and natural gas production for 2009 decreased 47% to $112.7 million from $209.8 million in 2008. Production volumes for oil and natural gas in 2009 increased 29% to 33.0 Bcfe from 25.6 Bcfe in 2008. Realized average natural gas sales price for 2009 decreased 59% to $3.20 per Mcf compared to $7.80 per Mcf in 2008, and the average oil sales price for 2009 decreased 41% to $58.85 per barrel from $99.74 per barrel in 2008. The increase in natural gas production was primarily due to the production from new wells in the Barnett Shale area.

The following table summarizes production volumes, average sales prices and operating revenues for our oil and natural gas operations for the years ended December 31, 2009 and 2008:

	December 31,		2009 Compared to 2008	
	2009	2008	Increase (Decrease)	% Increase (Decrease)
Production volumes-				
Oil and condensate (Mbbls)	174	186	(12)	(6)%
Natural gas (MMcf)[1]	32,002	24,513	7,489	31%
Average sales prices-				
Oil and condensate (per Bbl)	$ 58.85	$ 99.74	$ (40.89)	(41)%
Natural gas (per Mcf)	3.20	7.80	(4.60)	(59)%
Operating revenues (In thousands) -				
Oil and condensate	$ 10,217	$ 18,598	$ (8,381)	(45)%
Natural gas	102,482	191,231	(88,749)	(46)%
Other	1,380	6,848	(5,468)	(80)%
Total	$ 114,079	$ 216,677	$ (102,598)	(47)%

(1) Includes 1,975.2 and 965.7 MMcfe of natural gas liquids in 2009 and 2008, respectively.

Oil and natural gas operating expenses for 2009 decreased 20% to $30.2 million (or $0.91 per Mcfe) from $37.9 million (or $1.48 per Mcfe) in 2008. The decrease in operating expenses was due to lower severance taxes of $5.1 million associated with refunds from certain wells that qualified for a tight-gas sands tax credit for prior production periods and approximately $3.0 million in lower transportation gathering and treating costs in the Barnett Shale mainly attributable to a change in pricing and transportation contractual arrangements.

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 (discounted at ten percent) 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, ceiling test write-downs of $216.4 million ($138.0 million after tax) and $122.5 million ($78.1 million after tax), respectively, at March 31, 2009 and December 31, 2009. At December 31, 2008, the Company recorded a non-cash ceiling test write-down of $178.5 million ($116.0 million after-tax).

Depreciation, depletion and amortization (DD&A) expense for 2009 decreased 11% to $52.0 million from $58.3 million in 2008. This decrease was primarily due to impairment charges in the fourth quarter of 2008 and the first quarter of 2009 that reduced the depletable full-cost pool and due to lower overall finding costs of new reserves added primarily in the fourth quarter of 2009.

General and administration (G&A) expense for 2009 increased 29% to $30.1 million from $23.4 million in 2008. The increase in G&A was due primarily to an increase in non-cash, stock-based compensation of $5.3 million as a result of additional stock-based compensation awards. In addition, during 2009, we made a $1.0 million pledge to establish a Carrizo Oil & Gas, Inc. endowed scholarship fund at The University of Texas at Arlington, a university which is located within the area of our significant operations in the Barnett Shale.

The net gain on derivatives was $41.5 million for the year ended December 31, 2009, comprised of (1) $74.9 million of unrealized mark-to-market net gains on derivatives and (2) $33.4 million of net realized losses.

Interest expense and capitalized interest in 2009 were $38.3 million and $19.7 million, respectively, as compared to $30.3 million and $20.5 million in 2008, respectively. The increase in interest expense was attributable to increased borrowings under the Senior Credit Facility and higher effective interest rates.

Our overall effective tax rate was 35.6% for 2009 and 31.5% for 2008. The increase in the effective tax rate was due to higher state income taxes and lower non-deductible expense in 2009 as compared to 2008.

Year Ended December 31, 2008 Compared to the Year Ended December 31, 2007

Revenues from oil and natural gas production for 2008 increased 67% to $209.8 million from $125.8 million in 2007. Production volumes for oil and natural gas in 2008 increased 47% to 25.6 Bcfe from 17.5 Bcfe in 2007. Realized average natural gas sales price for 2008 increased 15% to $7.80 per Mcf compared to $6.77 per Mcf in 2007, and the average oil sales price for 2008 increased 40% to $99.74 per barrel from $71.42 per barrel in 2007. The increase in natural gas production was primarily due to the production from new wells in the Barnett Shale area.

The following table summarizes production volumes, average sales prices and operating revenues for our oil and natural gas operations for the years ended December 31, 2008 and 2007:

	December 31,		2008 Compared to 2007	
	2008	2007	Increase (Decrease)	% Increase (Decrease)
Production volumes-				
Oil and condensate (Mbbls)	186	241	(55)	(23)%
Natural gas (MMcf)[(1)]	24,513	16,042	8,471	53%
Average sales prices-				
Oil and condensate (per Bbl)	$ 99.74	$ 71.42	$ 28.32	40%
Natural gas (per Mcf)	7.80	6.77	1.03	15%
Operating revenues (In thousands) -				
Oil and condensate	$ 18,598	$ 17,197	$ 1,401	8%
Natural gas	191,231	108,592	82,639	76%
Other	6,848		6,848	100%
Total	$ 216,677	$ 125,789	$ 90,888	72%

(1) Includes 965.7 MMcfe of natural gas liquids in 2008.

Oil and natural gas operating expenses for 2008 increased 54% to $37.9 million (or $1.48 per Mcfe) from $24.7 million (or $1.41 per Mcfe) in 2007. The increase in total operating expenses was primarily due to (i) higher transportation gathering and treating costs of $4.5 million, (ii) higher saltwater disposal costs of $1.4 million, (iii) increased compression costs of $1.4 million and (iv) higher ad valorem taxes of $2.9 million.

The significant decline in oil and natural gas prices, indicated by average prices of $4.99 per Mcf for natural gas and $40.12 per Bbl for oil on December 31, 2008, caused the discounted present value (discounted at ten percent) of future net cash flows from proved oil and gas reserves to fall below the net book basis in the proved oil and gas properties. This resulted in a non-cash ceiling test write-down at the end of the fourth quarter of 2008 of $178.5 million ($116.0 million after tax).

DD&A expense for 2008 increased to $58.3 million from $41.9 million in 2007. This increase was primarily due to an increase in production volumes partially offset by a decrease in the DD&A rate primarily due to lower overall finding cost of new reserves added in 2008.

G&A expense for 2008 increased 24% to $23.4 million from $18.9 million for 2007. The increase in G&A was due primarily to (i) increased employee related and contractor costs of $1.2 million, (ii) increased stock-based compensation expense of $1.0 million and (iii) increased legal and professional fees of $0.8 million.

The net gain on derivatives of $37.5 million for the year ended December 31, 2008 was comprised of a $41.4 million of unrealized mark-to-market net gain on derivatives that was partially offset by $3.9 million of net realized losses.

In May 2008, we repaid our outstanding borrowings under the Second Lien Facility and terminated the facility. As a result, we recorded a $5.7 million loss associated with the early extinguishment of debt consisting of a $4.6 million non-cash write-off of deferred loan costs and $1.1 million in penalties paid for early retirement. In connection with the early termination, we settled the interest rate swaps and realized a $3.3 million loss, included in our gain/(loss) on derivatives, net.

Interest expense and capitalized interest in 2008 were $30.3 million and $20.5 million, respectively, as compared to $26.4 million and $11.7 million in 2007, respectively. These increases were largely attributable to approximately $6.9 million in non-cash interest expense associated with the amortization of the debt discount on the Senior Convertible Notes and increased debt outstanding during 2008. These increases were partially offset by the payoff of the higher cost Second Lien Credit Facility with the proceeds from the issuance of the Convertible Notes, which bore interest at a lower rate, and due to higher capitalized interest as a result of increased unproved leasehold costs in 2008.

Our overall effective tax rate was 31.5% for 2008 and 37.4% for 2007. The decrease in the effective tax rate was due to higher non-deductible expenses in 2008 as compared to 2007.

Liquidity and Capital Resources

2010 Capital and Exploration Expenditures Plan and Funding Strategy. For 2010, our Board has established a capital and exploration expenditures plan to spend $170 million, including $145.0 million for our drilling program (including $130.0 million for Barnett Shale development and $15.0 million for Marcellus Shale development) and $25 million for lease and seismic data acquisitions primarily in the Marcellus Shale and drilling and development in other project areas. If our development plan for the Huntington Field is approved by our joint venture during 2010, we may be required to invest up to an additional $20.0 million in facilities and drilling to develop this field in 2010. We intend to finance our 2010 capital expenditure plan primarily from the sources described below under Sources and Uses of Cash. We may be required to reduce or defer part of our 2010 capital expenditures plan if we are unable to obtain sufficient financing from these sources.

Sources and Uses of Cash. During the year ended December 31, 2009, capital expenditures, net of proceeds from asset sales, exceeded our net cash provided by operations. During 2009, we funded our capital expenditures with cash generated from operations, proceeds from the sale of non-core assets, proceeds from our joint venture with Sumitomo and net additional borrowings under the Senior Credit Facility. Potential primary 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 oil and gas field services. We hedge a portion of our production to reduce the downside risk of declining natural gas and oil prices.

Borrowings under the Senior Credit Facility. During the fourth quarter of 2009, the borrowing base under the Senior Credit Facility was increased to $350.0 million. At March 1, 2010, $138.2 million was available for borrowing under the Senior Credit Facility. The next borrowing base redetermination is currently scheduled for April 1, 2010.

Asset sales. In order to fund our capital expenditure plan, we may consider the sale of certain properties or assets that are not part of our core business, or are no longer deemed essential to our future growth, if we are able to sell such assets on terms that are acceptable to us. In October 2009, we completed the sale of our Mansfield pipelines and gathering system located in the Barnett Shale play for approximately $34.7 million. The net proceeds from the sale were used to reduce the debt outstanding under the Senior Credit Facility. We may consider the sale of additional non-core assets, including the possible sale of our interest in the Huntington Field located in the North Sea, provided that we can obtain terms that are acceptable to us.

Debt and equity offerings. 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.

Project financing in certain limited circumstances, particularly to fund all or a portion of our future development costs for the Huntington Field in the U.K. North Sea.

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

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, such as our joint venture in the Marcellus Shale play and our joint venture with 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. Our capital expenditures plan in 2010 provides for approximately \$145.0 million for drilling, and approximately \$25.0 million for lease and seismic data acquisitions primarily in the Marcellus Shale and drilling and development in other project areas. In 2010 we currently plan to drill 57 gross (38.1 net) wells in the Barnett Shale area, 11 gross (3.8 net) wells in the Marcellus Shale area and three gross (1.5 net) wells in our other areas. The actual number of wells drilled and capital expended depends on our available financing, cash flow, availability and cost of drilling rigs, land and partner issues and other factors. Capital expenditures do not include operating costs such as the steam costs that will be required for the multi-year development of our Camp Hill project. In addition to our capital expenditure program, we have contractual obligations as discussed below.

Overview of Cash Flow Activities. Cash flows provided by operating activities were $133.4 million, $148.8 million and $95.2 million for the years ended December 31, 2009, 2008 and 2007, respectively. The decrease from 2008 to 2009 was primarily due to a decrease in revenues largely attributable to lower natural gas prices. Despite our increase in natural gas production, suppressed natural gas prices could have a negative impact on our cash flow from operations and on our 2010 drilling plans.

Cash flows used in investing activities were $162.5 million for the year ended December 31, 2009 and related primarily to oil and gas property expenditures, partially offset by the sale of our Mansfield pipeline gathering system in the Barnett Shale play and the sale of working interests to Sumitomo for total net proceeds of approximately $48.5 million. Cash flows used in investing activities were $555.3 million for the year ended December 31, 2008 and related primarily to oil and gas property expenditures. The decrease in investing activities from 2008 was largely due to lower expenditures for oil and gas properties as we adjusted our drilling plans to the reduced demand for natural gas and lower natural gas prices. Cash flows used in investing activities of $227.7 million for the year ended December 31, 2007 were largely attributable to capital expenditures for oil and gas properties.

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 Senior Credit Facility. Net cash provided by financing activities for the year ended December 31, 2008 was $403.7 million and related primarily to net proceeds of $135.1 million from the issuance of common stock in February 2008, net proceeds of $365.3 million from the issuance of the Senior Convertible Notes and $401.0 million in additional borrowings under the Senior Credit Facility. These cash proceeds were partially offset by the payoff and termination of the second lien credit facility and partial paydown of the Senior Credit Facility. Net cash provided by financing activities for the year ended December 31, 2007 was $135.1 million and related primarily to the additional borrowings of $75.0 million under our second lien credit facility in January 2007 and net proceeds of $71.9 million from the issuance of common stock in September 2007. These cash proceeds were partially offset by the repayment of borrowings under our Senior Credit Facility.

Liquidity/Cash Flow Outlook.

The continued worldwide economic downturn may adversely affect our ability to access the capital markets in the future. We currently believe that cash generated from operations, supplemented by borrowings under the Senior Credit Facility, will be sufficient to fund our immediate needs. Cash generated from operations is primarily driven by production and commodity prices. While we have steadily increased production over the last few years oil and natural gas prices have declined since the third quarter of 2008. In an effort to mitigate declining prices, we hedge a portion of our production and, as of March 1, 2010, we had hedged approximately 35,397,000 MMBtu (68.7 MMcf per day for the year, or 73% of our estimated production from April through December 2010) of our 2010 natural gas production at a weighted average floor or swap price of $5.73 per MMBtu relative to WAHA and Houston Ship Channel prices. We believe the funds available to us under the Senior Credit Facility, $138.2 million at March 1, 2010, will be accessible to us. We are scheduled for a borrowing base redetermination on April 1, 2010, at which time our borrowing base may change. We currently expect that our borrowing base will increase based upon the increase to our proved reserves during the fourth quarter of 2009. However, the borrowing base is also affected by the future sales price assumptions for our oil and natural gas production that our banks use in their calculations. Our borrowing base may decrease if our banks believe that the price we will receive for our oil and natural gas production is substantially less than what their current assumptions are.

If cash from operations, funds available under the Senior Credit Facility and the other sources of cash described under Sources and Uses of Cash are insufficient to fund our 2010 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 2010 natural gas and oil exploration and development program, thereby adversely affecting the recoverability and ultimate value of our natural gas and oil properties.

Contractual Obligations

The following table sets forth estimates of our contractual obligations as of December 31, 2009:

	Payments Due by Year (In thousands)					
	Total	2010	2011	2012	2013	2014 and Thereafter
Long-term Debt[1]	$ 565,150	$	$	$ 191,400	$ 373,750	$
Interest on long-term debt[4]	73,490	22,264	22,264	20,786	8,176	
Operating Leases	2,642	1,328	1,314			
Drilling Contracts	33,797	25,418	8,379			
Pipeline Volume Commitment[2]	46,149	9,239	7,831	7,019	6,556	15,504
Asset retirement obligation	5,410	203	375	164	87	4,581
Other[3]	6,013	1,924	4,089			
Total Contractual Cash Obligations	$ 732,651	$ 60,376	$ 44,252	$ 219,369	$ 388,569	$ 20,085

(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) Includes a seven year firm transportation agreement for 80,000 MMBtus/d effective September 2009.

(3) Includes premiums on

long puts and other miscellaneous long-term liabilities.

(4) Interest on long term debt is based on the 4.375% rate on the Convertible Senior Notes and the December 31, 2009 average 3.2% rate outstanding under the Senior Secured Revolving Credit Facility.

Off Balance Sheet Arrangements

We currently do not have any off balance sheet arrangements.

Financing Arrangements

Senior Secured Revolving Credit Facility

We have a senior secured revolving credit facility (the Senior Credit Facility) with Wells Fargo Bank, N.A., as administrative agent. The Senior Credit Facility provides for a revolving credit facility up to the lesser of the borrowing base and $350.0 million. It is secured by substantially all of our proved oil and gas assets and is currently guaranteed by certain of our subsidiaries: CCBM, Inc.; CLLR, Inc.; Carrizo (Marcellus), LLC; Carrizo Marcellus Holdings, Inc.; Hondo Pipeline Inc; Bandelier Pipeline Holding, LLC and Mescalero Pipeline, LLC.

The Senior Credit Facility matures on October 29, 2012 and is subject to semi-annual borrowing base redetermination dates on March 31 and September 30.

In April 2009, we amended the Senior Credit Facility to, among other things, (1) adjust the maximum ratio of total net debt to Consolidated EBITDAX; (2) modify the calculation of total net debt for purposes of determining the ratio of total net debt to Consolidated EBITDAX to exclude the following amounts, which represent a portion of the Convertible Senior Notes deemed to be an equity component under the accounting guidelines related to convertible debt that may be settled in cash (including partial cash settlement) upon conversion: $51.3 million during 2009, $38.9 million during 2010, $26.0 million during 2011 and $12.7 million during 2012 until the maturity date; (3) add a new senior leverage ratio; (4) modify the interest rate margins applicable to Eurodollar loans; (5) modify the interest rate margins applicable to base rate loans; and (6) establish new procedures governing the modification of swap agreements.

In May 2009, we amended the Senior Credit Facility to, among other things, (1) provide that the aggregate notional volume of oil and natural gas subject to swap agreements may not exceed 80% of forecasted production from proved producing reserves, (as that term is defined in the Senior Credit Facility), for any month, (2) remove a provision that limited the maximum duration of swap agreements permitted under the Senior Credit Facility to five years, and (3) provide that the aggregate notional amount under interest rate swap agreements may not exceed the amount of borrowings then outstanding under the Senior Credit Facility.

If the outstanding principal balance of the revolving loans under the Senior Credit Facility exceeds the borrowing base at any time, 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, pledge additional collateral 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 ensuing six-month period. Those payments would be in addition to any payments that may come due as a result of the quarterly borrowing base reductions. Otherwise, any unpaid principal or interest 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 Base CD Rate plus 1.0% and the Federal Funds Effective Rate plus 0.5%, plus (b) a margin between 1.00% and 2.00% (depending on the then-current level of borrowing base usage), but such interest rate can never be lower than the adjusted Daily LIBO rate on such day plus a margin between 2.25% to 3.25% (depending on the current level of borrowing base usage). The interest rate on each Eurodollar loan will be the adjusted daily LIBO rate plus a margin between 2.25% to 3.25% (depending on the then-current level of borrowing base usage). At December 31, 2009, the average interest rate for amounts outstanding under the Senior Credit Facility was 3.2%.

We are subject to certain covenants under the amended terms of the Senior Credit Facility which include, but are not limited to, the maintenance of the following financial ratios: (1) a minimum current ratio of 1.00 to 1.00 (as defined in the Senior Credit Facility); and (2) a maximum total net debt to Consolidated EBITDAX (as defined in the Senior Credit Facility) of (a) 4.75 to 1.00 for each quarter ending on or after December 31, 2009 and on or before September 30, 2010, (b) 4.25 to 1.00 for the quarter ending December 31, 2010, and (c) 4.00 to 1.00 for each quarter ending on or after March 31, 2011; and (3) a maximum ratio of senior debt (which excludes certain amounts attributable to the Convertible Senior Notes) to Consolidated EBITDAX of 2.25 to 1.00.

Although we currently believe that we can comply with all of the financial covenants with our current business plan, the business plan is based on a number of assumptions, the most important of which is a relatively stable natural gas price at economically sustainable levels. If the price that we receive for our 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 in the Senior Credit Facility, including the financial covenants discussed above. In order to provide a further margin of comfort with regards to these financial covenants, we may seek to further reduce our capital and exploration plan, sell non-strategic assets, opportunistically modify or increase natural gas hedges or approach the lenders under the Senior Credit Facility for modifications of either or both of the financial covenants discussed above. There can be no assurance 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 the Senior Credit Facility if a precipitous decline in natural gas prices were to occur in the future. The Senior Credit Facility also places restrictions on indebtedness, dividends to shareholders, liens, investments, mergers, acquisitions, asset dispositions, repurchase or redemption of our common stock, speculative commodity transactions, transactions with affiliates and other matters.

The Senior Credit Facility is subject to customary events of default, the occurrence and continuation of which could result in the acceleration of amounts due under the facility by the agent or the lenders.

At December 31, 2009, we had $191.4 million of borrowings, and the amount available for borrowings was $158.6 million which can be used to fund working capital and our capital expenditure plan to the extent such amounts exceed the cash flow from operations.

Convertible Senior Notes

In May 2008, we 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 will be convertible, using a net share settlement process, into a combination of cash and our 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 our conversion obligation in excess of such principal amount.

The notes are convertible into our 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, we 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 our 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 our 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 June 30, 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 us 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. We 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 the Senior 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 and rank equal to all future senior unsecured debt but rank second in priority to the Senior Credit Facility.

In accordance with the accounting guidelines for convertible debt, 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 will be 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, and will result in an effective interest rate of approximately 8% for the Convertible Senior Notes.

Second Lien Credit Facility

On July 21, 2005, we entered into a Second Lien Credit Agreement with Credit Suisse, as administrative agent and collateral agent and the lenders party thereto (the Second Lien Credit Facility). The Second Lien Credit Facility, as amended, provided for a term loan facility in an aggregate principal amount of $225.0 million. In May 2008, we repaid in full the $219.9 million outstanding under the Second Lien Credit Facility and terminated the facility in connection with the issuance of the Convertible Senior Notes.

Public Offerings in 2008 and 2007

In February 2008, we sold 2,587,500 shares of our common stock in an underwritten public offering at a price of $54.50 per share, raising $135.1 million of net proceeds. With a portion of the proceeds we repaid $85.0 million of outstanding borrowings under the Senior Credit Facility. We used the remaining proceeds to fund a portion of our 2008 capital expenditure program.

In September 2007, we sold 1,800,000 shares of our common stock to certain qualified investors in a registered direct offering at a price of $41.40 per share, raising $71.9 million of net proceeds. We used the net proceeds to repay $54 million of outstanding borrowings under the Senior Credit Facility and to fund a portion of our 2007 capital expenditure program.

Lease Option Arrangements

In order to expand our lease acquisition efforts in the Marcellus Shale play, the Company elected to enter into a lease option agreement effective August 1, 2008 with Avista, our partner in the Marcellus Shale play. See Business and Properties Significant Project Areas; Marcellus Shale Area. The terms and conditions of the lease purchase option arrangement with Avista were generally consistent with lease option arrangements that we have traditionally entered into with other third parties. Avista paid approximately $27.5 million for the oil and gas leases under the lease purchase option agreement and subsequently contributed these properties at their cost to our Marcellus joint venture, effective August 1, 2008. This lease purchase option arrangement was terminated when that joint venture commenced.

We have continued to enter into lease purchase option arrangements with third parties from time to time. We currently have one lease purchase option arrangement described below with an unrelated third party. Strategically, these 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. Under this arrangement, we may until May 31, 2011 acquire up to $20 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 purchases a lease group under the Land Agreement, if any, we will 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. The warrants are subject to antidilution adjustments and may be exercised on a cashless basis.

We have 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 may pay 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).

We may twice extend the option for an additional 180 days each if we pay the third party an amount equal to five percent of the original purchase price for the applicable lease group upon each extension. If we do not exercise our option to purchase a lease group within the applicable option period, then the third party has two 30-day options, one commencing on the expiration of our option period for such lease group, and the other commencing on April 1, 2013, to exchange such lease group for certain of our acreage in the Marcellus Shale.

Effects of Inflation and Changes in Price

Our results of operations and cash flows are affected by changing natural gas and oil prices. The dramatic drop in natural gas and oil prices that began in 2008 and the continued depressed price of natural gas in 2009 has resulted in a significant drop in revenue per unit of production. Although operating costs have come down slightly in recent months, the rate of decline in natural gas and oil prices has been substantially greater. Historically, inflation has had a minimal effect on us. However, with interest rates at historic lows and as a result of the government attempt to stimulate the economy through expansion of the money supply, inflation could become a significant issue in the future.

Recently Adopted Accounting Pronouncements

On January 1, 2009, we adopted new accounting guidelines related to convertible debt instruments that may be settled in cash (including partial cash settlement) upon conversion. Under the accounting guidelines, issuers of convertible debt are required to separately account for the liability and equity components in a manner that reflects the entity s nonconvertible debt borrowing rate when interest cost is recognized in subsequent periods. The new accounting guidelines require retrospective application to the terms of instruments as they existed for periods presented. We retrospectively applied the accounting guidelines to the Convertible Senior Notes. We valued the Senior Convertible Notes as $309.6 million of debt and $64.2 million of equity, representing the fair value of the conversion premium of the convertible debt at the date of issuance and accordingly restated our balance sheet as of December 31, 2008 for the carrying value of debt and equity and restated our results of operations for interest expense, capitalized interest, and income taxes for the year ended December 31, 2008.

On January 1, 2009, we adopted and retroactively applied new accounting guidelines related to restricted stock and participating securities. Under the new accounting treatment, unvested share-based payment awards that contain non-forfeitable rights to dividends or dividend equivalents, whether paid or unpaid, are participating securities and shall be included in the computation of both basic and diluted earnings per share. These new guidelines require retroactive application for all periods presented. We determined that our restricted shares of common stock are participating securities and applied the new accounting treatment retrospectively to all periods presented.

In March 2008, new guidance for derivative disclosures was issued and requires transparency about the location and amounts of derivative instruments in an entity s financial statements, how derivative instruments and related hedged items are accounted for, and how derivative instruments and related hedged items affect an entity s financial position, financial performance and cash flows. We adopted these requirements effective January 1, 2009. Since this guidance only impacted disclosure requirements, the adoption of this guidance did not have a significant effect on our consolidated financial position, results of operations or cash flows.

On January 1, 2009, we adopted the guidance for non-financial assets and non-financial liabilities, except for items that are recognized or disclosed at fair value in the financial statements on a recurring basis, at least annually. The adoption of this guidance did not have a material impact on our financial position or results of operations.

In April 2009, guidance on the recognition of other-than-temporary impairments of investments in debt securities was issued. This pronouncement provides new presentation and disclosure requirements for other-than-temporary impairments of investments in debt and equity securities. We adopted the requirements of this pronouncement effective June 30, 2009, and it had no material impact on our consolidated financial statements.

In April 2009, accounting rules were amended to require disclosure about fair value of financial instruments in interim reporting periods, as well as in annual financial statements. We adopted the requirements of this pronouncement effective June 30, 2009, and included the additional disclosures in our notes to consolidated financial statements.

In May 2009, general standards of accounting for and disclosure of events that occur after the balance sheet date but before financial statements are issued were established to set forth: (1) the period after the balance sheet date during which management of a reporting entity should evaluate events or transactions that may occur for potential recognition or disclosure in the financial statements; (2) the circumstances under which an entity should recognize events or transactions occurring after the balance sheet date in its financial statements; and (3) the disclosures that an entity should make about events or transactions that occurred after the balance sheet date. We applied the requirement of this pronouncement effective June 30, 2009, and included additional disclosures in our notes to consolidated financial statements. In February 2010, the Financial Accounting Standards Board (FASB) amended these standards to no longer require disclosure of the date through which management evaluated subsequent events in the financial statements.

In June 2009, the FASB established the Accounting Standards Codification (Codification), which became effective July 1, 2009, as the single source of authoritative U.S. GAAP to be applied by nongovernmental entities. Rules and interpretive releases of the Commission under authority of federal securities laws are also sources of authoritative U.S. GAAP for Commission registrants. All other accounting literature excluded from the Codification will be considered non-authoritative. The subsequent issuances of new standards will be in the form of Accounting Standards Updates that will be included in the Codification. Generally, the Codification is not expected to change U.S. GAAP. We adopted the Codification effective September 30, 2009 and updated our disclosure references accordingly.

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 Commission 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 natural 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.

Additionally, the 12 month average pricing is required to value future cash inflows in the standardized measure of discounted future net cash flows related to our ownership interests in proved oil and natural gas reserves as of year-end 2009.

Summary of Critical Accounting Policies

The following summarizes several of 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 disclosure of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenues and expenses during the reporting periods. Actual results could differ from these estimates. The use of these estimates significantly affects our natural gas and oil properties through depletion and the full cost ceiling test, as discussed in more detail below.

Significant estimates include volumes of oil and natural gas reserves used in calculating depletion of proved oil and natural gas properties, future net revenues and abandonment obligations, impairment of undeveloped properties, future income taxes and related assets/liabilities, the collectability of outstanding accounts receivable, fair value of derivatives, stock-based compensation expense, contingencies and the results of future and current litigation. Oil and natural gas reserve estimates, which are the basis for unit-of-production depletion and the ceiling test, have numerous inherent uncertainties. The accuracy of any reserve estimate is a function of the quality of available data and of engineering and geological interpretation and judgment. Subsequent drilling results, testing and production may justify revision of such estimates. Accordingly, reserve estimates are often different from the quantities of oil and natural gas that are ultimately recovered. In addition, reserve estimates are vulnerable to changes in wellhead prices of crude oil and natural gas. Such prices have been volatile in the past and can be expected to be volatile in the future.

The significant estimates are based on current assumptions that may be materially affected by changes to future economic conditions such as the market prices received for sales of volumes of oil and natural gas, interest rates, the market value of our common stock and corresponding volatility and our ability to generate future taxable income. Future changes to these assumptions may affect these significant estimates materially in the near term.

Oil and Natural Gas Properties

We account for investments in natural gas and oil properties using the full-cost method of accounting. All costs directly associated with the acquisition, exploration and development of natural gas and oil properties are capitalized. These costs include lease acquisitions, seismic surveys, and drilling and completion equipment. We proportionally consolidate our interests in unincorporated joint ventures and natural gas and oil properties. We capitalized compensation costs and other costs of employees working directly on exploration activities of $5.6 million, $7.8 million and $4.5 million in 2009, 2008 and 2007, respectively. We expense maintenance and repairs as they are incurred.

Depreciation, depletion and amortization (DD&A) of our natural gas and oil properties is based on the unit-of-production method using estimates of proved reserve quantities. The depletion rate per Mcfe for 2009, 2008 and 2007 was $1.55, $2.23 and $2.36, respectively. Under the full cost method of accounting, the depletion rate is the current period production as a percentage of the total proved oil and natural gas reserves. Total proved reserves include both proved developed and proved undeveloped reserves. The depletion rate is applied to the net book value of our oil and natural gas properties (excluding unproved properties, exploratory wells in progress and capitalized interest) and estimated future development costs and dismantlement, restoration and abandonment costs net of estimated salvage value to calculate the depletion expense. Proved reserves materially impact depletion expense. If the proved reserves decline, then the depletion rate (the rate at which we record depletion expense) increases, reducing net income.

We account for dispositions of natural gas and oil properties as adjustments to capitalized costs with no gain or loss recognized, unless such adjustments would significantly alter the relationship between capitalized costs and proved reserves. We have not had any transactions that significantly alter that relationship.

Capitalized costs, less accumulated amortization and related deferred income taxes, are limited to a ceiling-test based on the estimated future net revenues, discounted at 10% per annum, from proved oil and natural gas reserves, less estimated future expenditures to be incurred in developing and producing the proved reserves, less any related income tax effects. If net capitalized costs exceed this limit, the excess is charged to earnings.

We incurred full-cost ceiling test impairments at December 31, 2009, March 31, 2009 and December 31, 2008. The December 31, 2009 full-cost ceiling test impairment of $122.5 million was based on oil, natural gas liquids and natural gas prices of $56.10, $23.18 and $3.30, respectively, which represents the unweighted average of oil and natural gas prices at the beginning of each month in the twelve-month period ending on December 31, 2009. The March 31, 2009 full cost ceiling test impairment was based on oil, natural gas liquids and natural gas prices of $45.13, $18.92 and $2.73 respectively, which represents prices subsequent to the balance sheet date, May 6, 2009, as allowed by Commission guidelines in effect at the time. The December 31, 2008 full cost ceiling test impairment was based on oil, natural gas liquids and natural gas prices of $40.12, $19.62 and $4.99, respectively, which represents prices in effect on the balance sheet date. The requirement to use the price in effect on the reporting date and the option to use a pricing date subsequent to the balance sheet date have been superseded by the new Commission rules governing the reporting of oil and natural gas reserves.

We have a significant amount of proved undeveloped reserves. We had 267.8 Bcfe, 239.1 Bcfe and 185.8 Bcfe of proved undeveloped reserves, representing 44%, 48% and 53% of our total proved reserves at December 31, 2009, 2008 and 2007, respectively. At December 31, 2009, under the new Commission rules governing the reporting of oil and natural gas reserves, we removed from our Camp Hill reserves all tertiary reserves previously classified as proved that were not associated with wells that we both plan to drill and into which we plan to inject steam during the next five years. See Business and Properties Significant Project Areas Camp Hill Area for further discussion of the Camp Hill properties. At December 31, 2009, we included 259.8 Bcfe of proved undeveloped reserves for our Barnett Shale area, or 97% of our total proved undeveloped reserves. We currently expect to develop all wells associated with these reserves within the next five years.

We expect our relatively low historical depletion rate to continue until the high level of nonproducing reserves to total proved reserves is reduced and the life of our proved developed reserves is extended through development drilling and/or the significant addition of new proved producing reserves through acquisition or exploration. If our level of total proved reserves, finding cost and current prices were all to remain constant, this continued build-up of capitalized costs increases the probability of a ceiling test write-down.

We depreciate other property and equipment using the straight-line method based on estimated useful lives ranging from five to 10 years.

Oil and Natural Gas Reserve Estimates

The proved reserve data as of December 31, 2009 included in this document are estimates prepared by Ryder Scott Company, LaRoche Petroleum Consultants, Ltd., and Fairchild & Stan, Inc., Independent Petroleum 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 certain economic assumptions regarding drilling and operating expense, capital expenditures, taxes and availability of funds. The Commission mandates some of these assumptions such as oil and natural gas prices and the present value discount rate.

Proved reserve estimates prepared by others may be substantially higher or lower than our estimates. Significant assumptions used by the third party engineers are assessed by our internal reserve team. All reserve reports prepared by third party 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 rates of production.

You should not assume that the present value of future net cash flows is the current market value of our estimated proved reserves. In accordance with Commission requirements, we based the estimated discounted future net cash flows from proved reserves on an unweighted arithmetic average of the first day of the month price for each month in the previous twelve month period, and costs on the date of the estimate, using a discount rate of 10%.

Our rate of recording depreciation, depletion and amortization expense for proved properties depends on our estimate of proved reserves. If these reserve estimates decline, the rate at which we record these expenses will increase. A 10% increase or decrease in our proved reserves would have increased or decreased our depletion expense by 10% for the year ended December 31, 2009.

Derivative Instruments

We use derivatives, typically fixed-rate swaps, costless collars, puts, calls and basis differential swaps to manage price risk underlying our oil and gas production. We also used derivatives to manage the variable interest rate on the Second Lien Credit Facility prior to its termination in May 2008. For a discussion of the impact of changes in the prices of oil and gas on our hedging transactions, see Volatility of Oil and Natural Gas Prices below.

Upon entering into a derivative contract, we either designate the derivative instrument as a hedge of the variability of cash flow to be received (cash flow hedge) or the derivative must be accounted for as a non-designated derivative. All of our derivative instruments for the years ended December 31, 2009, 2008 and 2007 were treated as non-designated derivatives and the unrealized gain/(loss) related to the change in fair value was included in our earnings as gain/(loss) on derivatives, net.

Our Board of Directors sets all of our risk management policies and reviews volume limitations, types of instruments and counterparties, on a quarterly basis. These policies require that derivative instruments be executed only by either the President or Chief Financial Officer after consultation and concurrence by the President, Chief Financial Officer and Chairman of the Board. The master contracts with the approved counterparties identify the

President and Chief Financial Officer as the only representatives authorized to execute trades. The Board of Directors also reviews the status and results of derivative activities quarterly.

Income Taxes

Deferred income taxes are recognized at each year end 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 future taxable income based upon our estimated 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 under accounting standards, the deferred tax assets are reduced by a valuation allowance. However, despite our attempt to make an accurate estimate, the ultimate utilization of our deferred tax assets is highly dependent upon our actual production and the realization of taxable income in future periods.

Contingencies

Liabilities and other contingencies are recognized upon determination of an exposure when it is both probable that an asset has been impaired or that a liability has been incurred and that the amount of such loss is reasonably estimable.

Volatility of Oil and Natural Gas Prices

Our revenues, future rate of growth, results of operations, financial condition and ability to borrow funds or obtain additional capital, as well as the carrying value of our properties, are substantially dependent upon prevailing prices of oil and natural gas. See Item 1A. Risk Factors Natural gas and oil prices are highly volatile, and have declined significantly since mid-2008, and lower prices will negatively affect our financial condition planned, capital expenditures and results of operations.

We periodically review the carrying value of our oil and natural gas properties under the full cost accounting rules of the Commission. See Summary of Critical Accounting Policies Oil and Natural Gas Properties and Item 1A. Risk Factors We may record ceiling limitation write-downs that would reduce our shareholders equity.

To mitigate some of our commodity price risk, we use derivatives, typically fixed-rate swaps, costless collars, puts, calls and basis differential swaps. We do not hold or issue derivative instruments for trading purposes.

The following table includes oil and natural gas derivative positions settled during the years ended December 31, 2009, 2008 and 2007 and the unrealized gain (loss) associated with the outstanding oil and natural gas derivatives at December 31, 2009, 2008 and 2007.

	December 31,		
	2009	**2008**	**2007**
Oil positions settled (Bbls)	5,900	64,100	52,000
Natural gas positions settled (MMBtu)	26,066,000	15,733,000	7,846,000
Realized gain ($ millions) (1)	$ 74.9	$ (1.9)	$ 6.4
Unrealized gain (loss) ($ millions) (1)	$ (33.4)	$ 41.1	$ (5.2)

(1) Included in gain (loss) on derivatives, net in the Consolidated Statements of Operations.

At December 31, 2009, approximately 58% of our open natural gas hedges were with Credit Suisse, 32% were with Shell Energy North America (US), L.P. and the remaining 10% were with Credit Agricole CIB.

While the use of derivative financial instruments limits the downside risk of adverse price movements, it may also limit our ability to benefit from increases in the prices of natural gas and oil. We enter into the majority of our derivative transactions with three counterparties and have a netting agreement in place with those counterparties. We do not obtain collateral to support the agreements but monitor the financial viability of counterparties and believe our credit risk is minimal on these transactions. Under these arrangements, payments are received or made based on the differential between a fixed and a variable product price. These agreements are settled in cash at expiration or exchanged for physical delivery contracts. In the event of nonperformance, we would be exposed to price risk. We have additional risk of financial loss because the price received for the product at the actual physical delivery point may differ from the prevailing price at the delivery point required for settlement of the financial instruments. Moreover, our derivative

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arrangements generally do not apply to all of our production and thus provide only partial price protection against declines in commodity prices. We expect that the amount of our hedges will vary from time to time.

Our natural gas derivative transactions are generally settled based upon the average of the reporting settlement prices on the Houston Ship Channel or WAHA index for the last three trading days of a particular contract month.

At December 31, 2009 we had the following open derivative positions:

	Natural Gas Swaps		Natural Gas Collars		
Quarter	MMbtus[1]	Average Fixed Price[2]	MMbtus[1]	Average Floor Price[2]	Average Ceiling Price[2]
First Quarter 2010	4,140,000	$5.51	2,070,000	$7.29	$8.96
Second Quarter 2010	4,641,000	5.52	1,092,000	5.50	6.99
Third Quarter 2010	3,496,000	5.75	1,564,000	5.76	7.31
Fourth Quarter 2010	3,036,000	5.83	1,840,000	6.12	7.57
First Quarter 2011	2,430,000	5.92	1,080,000	7.84	9.84
Second Quarter 2011	1,820,000	5.64	455,000	7.75	9.75
Third Quarter 2011	2,208,000	5.74	828,000	7.55	9.40
Fourth Quarter 2011	2,208,000	5.77	736,000	7.88	9.83
First Quarter 2012	1,365,000	6.22	1,001,000	8.04	9.96
Second Quarter 2012	910,000	5.88	455,000	7.80	9.80
Third Quarter 2012	1,472,000	6.06	644,000	6.41	7.91
Fourth Quarter 2012	1,472,000	6.09	644,000	6.48	8.43
TOTAL	29,198,000		12,409,000		

(1) During 2009, we entered into (1) a $5.00 put, a $5.85 long-call and an $7.65 short-call with respect to a portion of our production hedged with swaps (10,000 MMBtus per day) in 2011, (2) a $5.05 put, a $5.90 long call and a $7.70 short call with respect to a portion of our production hedged with swaps (10,000 MMBtu per

day) in 2012 and (3) a $3.93 put, a $5.58 long-call and a $6.08 short-call with respect to a portion of our production hedged with swaps (20,000 MMBtus per day) for April through October of 2010.

The table below presents additional put positions we have entered into associated with a portion of hedged volumes presented above:

Quarter	MMBtus	Put Price
Second Quarter 2010	455,000	$3.74
Third Quarter 2010	920,000	4.31
Fourth Quarter 2010	1,196,000	4.61
First Quarter 2011	1,530,000	5.53
Second Quarter 2011	910,000	5.65
Third Quarter 2011	1,288,000	5.59
Fourth Quarter 2011	1,196,000	5.58
First Quarter 2012	1,911,000	5.46
Second Quarter 2012	1,365,000	5.45
Third Quarter 2012	1,564,000	4.97
Fourth Quarter 2012	1,564,000	4.98

(2) Based on Houston Ship Channel (HSC) and WAHA spot prices.

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In addition, we sold the following natural gas long put positions:

Quarter	MMBtus	Average Fixed Price
Second Quarter 2010	300,000	$ 5.86
Third Quarter 2010	920,000	5.86
Fourth Quarter 2010	920,000	5.86
First Quarter 2011	900,000	5.80
Second Quarter 2011	910,000	5.80
Third Quarter 2011	920,000	5.80
Fourth Quarter 2011	920,000	5.80

Item 7A. Qualitative and Quantitative Disclosures about Market Risk

Commodity Risk. Our major market risk exposure is the commodity pricing applicable to our oil and natural gas production. Realized commodity prices received for such production are primarily driven by the prevailing worldwide price for oil and spot prices applicable to 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 natural gas production would have an approximate $11.3 million impact on our 2009 annual revenues.

To mitigate some of our commodity risk, we use derivatives, typically fixed-rate swaps, costless collars, puts, calls, and basis differential swaps. We do not hold or issue derivative instruments for trading purposes. The net gain realized by us related to these instruments was $72.4 million, $0.6 million and $5.8 million for the years ended December 31, 2009, 2008 and 2007, respectively.

Financial Instruments and Debt Maturities. Our financial instruments consist of cash and cash equivalents, accounts receivable, accounts payable and bank borrowings, including borrowings under the Senior Credit Facility. The carrying amounts of cash and cash equivalents, accounts receivable and accounts payable approximate fair value due to the highly liquid nature of these short-term instruments. The fair values of the bank and vendor borrowings approximate the carrying amounts as of December 31, 2009 and 2008, and were determined based upon interest rates currently available to us for borrowings with similar terms. The fair value of the Convertible Senior Notes at December 31, 2009 was approximately $321.7 million. Scheduled maturities of long-term debt are $0 in 2010 and 2011, $191.4 million in 2012 and $373.8 million in 2013.

Item 8. Financial Statements and Supplementary Data

The response to this item is included elsewhere in this report.

Item 9. Changes 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 Commission) 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 Commission 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 Exchange Act Rules 13a-15(b) and 15d-15(b), 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 Exchange Act Rules 13a-15(e) and 15d-15(e)) as of the end of the period covered by this report. 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 Commission under the Exchange Act, is recorded, processed, summarized and reported within the time periods specified by the Commission 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 2009 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, 2009. 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, 2009.

KPMG LLP, our independent registered public accounting firm that audited our consolidated financial statements, has also issued its own report on the effectiveness of our internal control over financial reporting as of December 31, 2009, 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, 2009 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 by reference to our definitive Proxy Statement (the 2010 Proxy Statement) for our 2010 annual meeting of shareholders. The 2010 Proxy Statement will be filed with the Commission not later than 120 days subsequent to December 31, 2009.

Pursuant to Item 401(b) of Regulation S-K, the information required by this item with respect to our executive officers is set forth in Part I of this report.

Item 11. Executive Compensation

The information required by this item is incorporated herein by reference to the 2010 Proxy Statement, which will be filed with the Commission not later than 120 days subsequent to December 31, 2009.

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

Information required by this item is incorporated herein by reference to the 2010 Proxy Statement, which will be filed with the Commission not later than 120 days subsequent to December 31, 2009.

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

The information required by this item is incorporated herein by reference to the 2010 Proxy Statement, which will be filed with the Commission not later than 120 days subsequent to December 31, 2009.

Item 14. Principal Accountant Fees and Services

The information required by this item is incorporated by reference to the 2010 Proxy Statement, which will be filed with the Commission not later than 120 days subsequent to December 31, 2009.

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 report.

(a)(2) Financial Statement Schedules

None.

(a)(3) Exhibits

EXHIBIT INDEX

Exhibit Number	Description
2.1	Combination Agreement by and among the Company, Carrizo Production, Inc., Encinitas Partners Ltd., La Rosa Partners Ltd., Carrizo Partners Ltd., Paul B. Loyd, Jr., Steven A. Webster, S.P. Johnson IV, Douglas A.P. Hamilton and Frank A. Wojtek dated as of September 6, 1997 (incorporated herein by reference to Exhibit 2.1 to the Company s Registration Statement on Form S-1 (Registration No. 333-29187)).
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)).

	10.1	Amendment No. 1 to the Letter Agreement Regarding Participation in the Company s 2001 Seismic and Acreage Program, dated June 1, 2001 (incorporated herein by reference to Exhibit 4.2 to the Company s Quarterly Report on Form 10-Q for the quarter ended June 30, 2001).
*	10.2	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).

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Exhibit Number	Description
* 10.3	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).
* 10.4	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).
* 10.5	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).
* 10.6	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).
* 10.7	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).
* 10.8	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).
* 10.9	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).
* 10.10	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).
* 10.11	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).
* 10.12	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).
* 10.13	Form of 2009 Employee Restricted Stock Unit Award Agreement (with performance-based vesting and time-based vesting) (incorporated herein by reference to Exhibit 10.7 to the Company s Current Report on Form 8-K filed on June 9, 2009).
* 10.14	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).

*	10.15	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. 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).

Exhibit Number	Description
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 May 25, 2006 among Carrizo Oil & Gas, Inc., as Borrower, Certain Subsidiaries of Borrower, as Guarantors, the Lenders party thereto, JPMorgan Chase Bank, National Association, as Administrative Agent, and J.P. Morgan Securities Inc., as Sole Bookrunner and Lead Arranger (incorporated herein by reference to Exhibit 10.1 to the Company s Current Report on Form 8-K filed on May 30, 2006).
10.25	First Lien Stock Pledge and Security Agreement dated as of May 25, 2006, by Carrizo Oil & Gas, Inc., in favor of JPMorgan Chase Bank, National Association, as Administrative Agent (incorporated herein by reference to Exhibit 10.2 to the Company s Current Report on Form 8-K filed on May 30, 2006).
10.26	Second Amendment effective as of September 11, 2007 to Credit Agreement dated as of May 25, 2006 among Carrizo Oil & Gas, Inc., as Borrower, Certain Subsidiaries of Borrower, as Guarantors, JPMorgan Chase Bank, National Association, as Administrative Agent and Lender, and Guaranty Bank as Lender (incorporated herein by reference to Exhibit 10.1 to the Company s Current Report on Form 8-K filed on September 11, 2007).
10.27	Third Amendment effective as of December 20, 2007 to Credit Agreement dated as of May 25, 2006 among Carrizo Oil & Gas, Inc., as Borrower, Certain Subsidiaries of Borrower, as Guarantors, JPMorgan Chase Bank, National Association, as Administrative Agent and Lender, and Guaranty Bank as Lender (incorporated by reference to Exhibit 10.48 to the Company s Annual Report on Form 10-K for the year ended December 31, 2008).
10.28	Fourth Amendment to Credit Agreement, dated as of May 20, 2008, by and among Carrizo Oil & Gas, Inc. and certain subsidiaries thereof, the Lenders party thereto and JPMorgan Chase Bank, N.A., as Administrative Agent (incorporated herein by reference to Exhibit 10.1 to the Company s Current Report on Form 8-K filed on May 22, 2008).
10.29	Fifth Amendment to Credit Agreement dated as of June 11, 2008 to Credit Agreement dated as of May 25, 2006 among Carrizo Oil & Gas, Inc., as Borrower, Certain Subsidiaries of Borrower, as Guarantors, JPMorgan Chase Bank, N.A., as Administrative Agent, 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 July 11, 2008).
10.30	Sixth Amendment dated as of July 7, 2008 to Credit Agreement dated as of May 25, 2006 among Carrizo Oil & Gas, Inc., as Borrower, Certain Subsidiaries of Borrower, as Guarantors, JPMorgan Chase Bank, N.A., as Administrative Agent, and the Lenders party thereto (incorporated herein by reference to Exhibit 10.2 to the Company s Current Report on Form 8-K filed on July 11, 2008).
10.31	Seventh Amendment dated as of October 29, 2008 to Credit Agreement dated as of May 25, 2006 among Carrizo Oil & Gas, Inc., as Borrower, Certain Subsidiaries of Borrower, as Guarantors, the Lenders party thereto, JPMorgan Chase Bank, N.A., as resigning administrative agent and as

	resigning issuing bank, and Guaranty Bank, as successor administrative agent and as successor issuing bank (incorporated herein by reference to Exhibit 10.1 to the Company s Current Report on Form 8-K filed on November 4, 2008).
10.32	Lender Certificate dated December 16, 2008 of Union Bank of California, N.A. regarding joinder as Lender to Credit Agreement, as amended, dated as of May 25, 2006 among Carrizo Oil & Gas, Inc., as Borrower, Certain Subsidiaries of Borrower, as Guarantors, Guaranty Bank, as Administrative Agent 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 December 22, 2008).
10.33	Eighth Amendment dated as of April 22, 2009 to Credit Agreement dated May 25, 2006 by and among Carrizo Oil & Gas, Inc., as Borrower, Certain Subsidiaries of Borrower, as Guarantors, the Lenders party thereto, and Guaranty Bank, as administrative agent (incorporated herein by reference to Exhibit 10.1 to the Company s Current Report on Form 8-K filed on April 28, 2009).
10.34	Ninth Amendment dated as of April 30, 2009 to Credit Agreement dated May 25, 2006 by and among Carrizo Oil & Gas, Inc., as Borrower, Certain Subsidiaries of Borrower, as Guarantors, the Lenders party thereto, and Guaranty Bank, as administrative agent (incorporated herein by reference to Exhibit 10.1 to the Company s Current Report on Form 8-K filed on May 6, 2009).
10.35	Tenth Amendment to Credit Agreement dated as of May 20, 2009 among Carrizo Oil & Gas, Inc., as Borrower, certain Subsidiaries of Borrower, as Guarantors, the Lenders party thereto, Guaranty Bank, as resigning administrative agent and as resigning issuing bank, and Wells Fargo Bank, N.A., as successor administrative agent and as successor issuing bank (incorporated herein by reference to Exhibit 10.1 to the Company s Current Report on Form 8-K filed on May 27, 2009).

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Exhibit Number	Description
10.36	Lender Certificate dated June 5, 2009 of Calyon New York Branch regarding joinder as Lender to Credit Agreement, as amended, dated as of May 25, 2006 among Carrizo Oil & Gas, Inc., as Borrower, Certain Subsidiaries of Borrower, as Guarantors, Guaranty Bank, as Administrative Agent 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 June 9, 2009).
10.37	Eleventh Amendment to Credit Agreement dated as of December 16, 2009 among Carrizo Oil & Gas, Inc., as Borrower, certain Subsidiaries of the Borrower, as Guarantors, the Lenders party thereto, and Wells Fargo Bank, N.A., as administrative agent and issuing bank (incorporated herein by reference to Exhibit 10.1 to the Company s Current Report on Form 8-K filed on December 17, 2009).
10.38	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).
10.39	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).
16.1	Letter dated June 3, 2009 from Pannell Kerr Forster of Texas, P.C. to the Securities and Exchange Commission regarding a change in certifying accountant (incorporated herein by reference to Exhibit 16.1 to the Company s Current Report on Form 8-K filed on June 4, 2009).
21.1	Subsidiaries of the Company.
23.1	Consent of KPMG LLP.
23.2	Consent of Pannell Kerr Forster of Texas, P.C.
23.3	Consent of Ryder Scott Company Petroleum Engineers.
23.4	Consent of Fairchild & Stan, Inc.
23.5	Consent of LaRoche Petroleum Consultants, Ltd.
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, 2009.

99.2	Summary of Reserve Report and Report of Fairchild & Stan, Inc. as of December 31, 2009.
99.3	Summary of Reserve Report and Report of LaRoche Petroleum Consultants, Ltd. as of December 31, 2009.

Incorporated by reference as indicated.

* Management contract or compensatory plan or arrangement.

CARRIZO OIL & GAS, INC.
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 sheet of Carrizo Oil & Gas, Inc. and subsidiaries (the Company) as of December 31, 2009 and the related consolidated statements of operations, shareholders equity, and cash flows for the year ended December 31, 2009. 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 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 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, assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audit provides 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, 2009, and the results of their operations and their cash flows for the year ended December 31, 2009, in conformity with U.S. generally accepted accounting principles.

As discussed in note 2 to the consolidated financial statements, the Company changed its method of estimating oil and natural gas reserves and as of December 31, 2009 due to the adoption of Accounting Standards Update No. 2010-03, *Oil and Gas Reserve Estimation and Disclosures*. Also, as discussed in note 2 to the consolidated financial statements, on January 1, 2009, the Company changed its method of accounting for convertible debt instruments.

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, 2009, based on *Internal Control Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO), and our report dated March 16, 2010 expressed an unqualified opinion on the effectiveness of the Company s internal control over financial reporting.

/s/KPMG LLP
Houston, Texas
March 16, 2010

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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, 2009, 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, 2009, 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 sheet of Carrizo Oil & Gas, Inc. and subsidiaries as of December 31, 2009, and the related consolidated statements of operations, shareholders equity, and cash flows for the year ended December 31, 2009, and our report dated March 16, 2010 expressed an unqualified opinion on those consolidated financial statements.

/s/KPMG LLP
Houston, Texas
March 16, 2010

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

The Board of Directors and Shareholders of
Carrizo Oil & Gas, Inc.

We have audited the accompanying consolidated balance sheet of Carrizo Oil & Gas, Inc. as of December 31, 2008 and the related consolidated statements of operations, shareholders equity and cash flows for each of the two years in the period ended December 31, 2008. These financial statements are the responsibility of the Company s management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. 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 financial statements referred to above present fairly, in all material respects, the financial position of Carrizo Oil & Gas, Inc. at December 31, 2008 and the results of its operations and its cash flows for each of the two years in the period ended December 31, 2008, in conformity with U.S. generally accepted accounting principles.

/s/ Pannell Kerr Forster of Texas, P.C.
Houston, Texas
March 12, 2009
(Except for Notes 4, 5, 6 and 13 for which
the date is August 17, 2009)

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CARRIZO OIL & GAS, INC.

CONSOLIDATED BALANCE SHEETS

	December 31, 2009	December 31, 2008
	(In thousands, except per share amount)	
ASSETS		
CURRENT ASSETS:		
Cash and cash equivalents	$ 3,837	$ 5,184
Accounts receivable, trade (net of allowance for doubtful accounts of $2,036 and $1,264 at December 31, 2009 and 2008, respectively)	21,341	21,458
Advances to operators	540	336
Fair value of derivative financial instruments	8,404	26,008
Prepayments and deposits	1,278	3,335
Total current assets	35,400	56,321
PROPERTY AND EQUIPMENT, net full-cost method of accounting for oil and natural gas properties (including costs not subject to amortization of $330,607 and $378,634 at December 31, 2009 and 2008, respectively)	733,700	986,629
DEFERRED FINANCING COSTS, NET	9,738	8,430
INVESTMENTS	3,358	3,274
FAIR VALUE OF DERIVATIVE FINANCIAL INSTRUMENTS	6,477	15,876
DEFERRED TAX ASSET	70,217	
OTHER ASSETS	4,217	1,172
TOTAL ASSETS	$ 863,107	$ 1,071,702
LIABILITIES AND SHAREHOLDERS EQUITY		
CURRENT LIABILITIES:		
Accounts payable, trade	$ 47,297	$ 46,683
Accrued liabilities	30,293	54,149
Advances for joint operations	1,739	3,815
Current maturities of long-term debt	148	173
Deferred tax liability	1,474	9,103
Other current liabilities	1,777	
Total current liabilities	82,728	113,923
LONG-TERM DEBT, net of current maturities and debt discount	520,188	475,788
ASSET RETIREMENT OBLIGATION	5,410	6,503
FAIR VALUE OF DERIVATIVE FINANCIAL INSTRUMENTS	2,818	
DEFERRED INCOME TAXES		34,778
DEFERRED CREDITS	4,354	625
COMMITMENTS AND CONTINGENCIES		
SHAREHOLDERS EQUITY:		
Common stock, par value $0.01 per share (90,000 shares authorized with 31,100 and 30,860 issued and outstanding at December 31, 2009 and 2008, respectively)	311	309
Additional paid in capital	431,757	420,778

Retained earnings	(184,548)	20,297
Accumulated other comprehensive income (loss), net of tax	89	(1,299)
Total shareholders equity	247,609	440,085
TOTAL LIABILITIES AND SHAREHOLDERS EQUITY	$ 863,107	$ 1,071,702

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

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CARRIZO OIL & GAS, INC.

CONSOLIDATED STATEMENTS OF OPERATIONS

	For the Years Ended December 31, 2009	2008	2007
	(In thousands, except per share amounts)		
OIL AND NATURAL GAS REVENUES	$ 114,079	$ 216,677	$ 125,789
COSTS AND EXPENSES:			
Oil and natural gas operating expenses	30,204	37,885	24,662
Third party gas purchases	1,497	6,570	
Depreciation, depletion and amortization	52,005	58,311	41,899
Impairment of oil and natural gas properties	338,914	178,470	
General and administrative	30,136	23,425	18,912
Accretion expense related to asset retirement obligation	308	154	374
Total costs and expenses	453,064	304,815	85,847
OPERATING INCOME (LOSS)	(338,985)	(88,138)	39,942
OTHER INCOME AND EXPENSES:			
Gain (loss) on derivatives, net	41,465	37,499	(1,366)
Loss on extinguishment of debt		(5,689)	
Impairment of investment in Pinnacle Gas Resources, Inc.	(2,091)		
Interest income	13	269	691
Interest expense	(38,286)	(30,257)	(26,403)
Capitalized interest	19,696	20,527	11,718
Other income, net	36	17	130
INCOME (LOSS) BEFORE INCOME TAX EXPENSE (BENEFIT)	(318,152)	(65,772)	24,712
INCOME TAX EXPENSE (BENEFIT)	(113,307)	(20,725)	9,243
NET INCOME (LOSS)	$ (204,845)	$ (45,047)	$ 15,469
OTHER COMPREHENSIVE INCOME (LOSS):			
Increase (decrease) in market value of investment in Pinnacle Gas Resources, Inc., net of income taxes	55	(6,724)	5,425
Reclassification of cumulative decrease in market value of investment in Pinnacle Gas Resources, Inc., net of taxes	1,333		
COMPREHENSIVE INCOME (LOSS)	$ (203,457)	$ (51,771)	$ 20,894
BASIC EARNINGS (LOSS) PER COMMON SHARE	$ (6.61)	$ (1.49)	$ 0.58
DILUTED EARNINGS (LOSS) PER COMMON SHARE	$ (6.61)	$ (1.49)	$ 0.57
WEIGHTED AVERAGE SHARES OUTSTANDING:			
BASIC	31,006	30,326	26,641

DILUTED	31,006	30,326	27,120

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

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CARRIZO OIL & GAS, INC.

CONSOLIDATED STATEMENTS OF SHAREHOLDERS EQUITY

	Common Stock	
	Shares	**Amount**
	(In thousands, except share amounts)	
BALANCE, January 1, 2007	25,980,605	$ 260
Common stock issued, net of offering cost	1,800,000	18
Stock options exercised for cash	124,148	1
Stock-based compensation		
Restricted stock awards, net of forfeitures	111,839	1
Common stock repurchased to settle tax withholding obligations	(7,440)	
Other comprehensive income:		
Fair value adjustment to investment in Pinnacle Gas Resources, Inc., net of income tax expense of $2,921		
Net income		
Total comprehensive income		
BALANCE, December 31, 2007	28,009,152	$ 280
Common stock issued, net of offering cost	2,587,500	26
Bifurcation of equity premium related to Senior Secured Notes		
Stock options exercised for cash	65,400	1
Stock-based compensation		
Restricted stock awards, net of forfeitures	203,306	2
Common stock repurchased to settle tax withholding obligations	(5,711)	
Other comprehensive loss:		
Fair value adjustment to investment in Pinnacle Gas Resources, Inc., net of income tax benefit of $3,621		
Net loss		
Total comprehensive loss		
BALANCE, December 31, 2008	30,859,647	$ 309
Stock options exercised for cash	5,000	
Stock-based compensation		
Restricted stock and stock option awards, net of forfeitures	226,286	2
Other	9,500	
Other comprehensive loss:		
Fair value adjustment to investment in Pinnacle Gas Resources, Inc., net of income tax expense of $31		
Reclassification of cumulative decrease in market value of investment in Pinnacle Gas Resources, Inc., net of income tax expense of $758		
Net loss		
Total comprehensive loss		
BALANCE, December 31, 2009	31,100,433	$ 311

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

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CARRIZO OIL & GAS, INC.
CONSOLIDATED STATEMENTS OF SHAREHOLDERS EQUITY

	Additional Paid in Capital	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Shareholders Equity
	(In thousands)			
BALANCE, January 1, 2007	$ 162,139	$ 49,875	$	$ 212,274
Common stock issued, net of offering cost	71,908			71,926
Stock options exercised for cash	1,030			1,031
Stock-based compensation	5,041			5,041
Restricted stock awards, net of forfeitures	(136)			(135)
Common stock repurchased to settle tax withholding obligations	(310)			(310)
Other comprehensive income:				
Fair value adjustment to investment in Pinnacle Gas Resources, Inc., net of income tax expense of $2,921			5,425	5,425
Net income		15,469		15,469
Total comprehensive income				20,894
BALANCE, December 31, 2007	$ 239,672	$ 65,344	$ 5,425	$ 310,721
Common stock issued, net of offering cost	135,049			135,075
Bifurcation of equity premium related to Senior Convertible Notes	40,207			40,207
Stock options exercised for cash	261			262
Stock-based compensation	6,013			6,013
Restricted stock awards, net of forfeitures	(63)			(61)
Common stock repurchased to settle tax withholding obligations	(361)			(361)
Other comprehensive loss:				
Fair value adjustment to investment in Pinnacle Gas Resources, Inc., net of income tax benefit of $3,621			(6,724)	(6,724)
Net loss		(45,047)		(45,047)
Total comprehensive loss				(51,771)
BALANCE, December 31, 2008	$ 420,778	$ 20,297	$ (1,299)	$ 440,085
Stock options exercised for cash	9			9
Stock-based compensation	10,543			10,543
Restricted stock and stock option awards, net of forfeitures	304			306
Other	123			123

Other Comprehensive loss:				
Fair value adjustment to investment in Pinnacle Gas Resources, Inc., net of income tax expense of $31			55	55
Reclassification of cumulative decrease in market value of investment in Pinnacle Gas Resources, Inc., net of income tax expense of $758			1,333	1,333
Net loss		(204,845)		(204,845)
Total comprehensive loss				(203,457)
BALANCE, December 31, 2009	$ 431,757	$ (184,548)	$ 89	$ 247,609

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

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CARRIZO OIL & GAS, INC.

CONSOLIDATED STATEMENTS OF CASH FLOWS

	For the Years Ended December 31,		
	2009	2008	2007
		(In thousands)	
CASH FLOWS FROM OPERATING ACTIVITIES:			
Net income (loss)	$ (204,845)	$ (45,047)	$ 15,469
Adjustments to reconcile net income (loss) to net cash provided by operating activities			
Depreciation, depletion and amortization	52,005	58,311	41,899
Impairment of oil and natural gas properties	338,914	178,470	
Fair value (gain) loss on derivative financial instruments	33,401	(43,859)	8,023
Provision for allowance for doubtful accounts	772	(166)	(209)
Accretion of discounts on asset retirement obligations	308	154	374
Loss on extinguishment of debt		4,601	
Stock-based compensation	11,297	5,952	4,907
Deferred income taxes	(113,374)	(20,920)	8,329
Amortization of equity premium associated with Senior Convertible Notes	5,898	1,825	
Impairment of investment in Pinnacle Gas Resources, Inc.	2,091		
Other	5,865	5,272	1,623
Changes in operating assets and liabilities			
Accounts receivable, trade	(656)	5,119	(330)
Other assets	(876)	(3,661)	(210)
Accounts payable, trade	558	(1,476)	15,463
Accrued liabilities	2,014	4,179	(107)
Net cash provided by operating activities	133,372	148,754	95,231
CASH FLOWS FROM INVESTING ACTIVITIES:			
Capital expenditures	(182,907)	(571,291)	(247,003)
Change in capital expenditure accrual	(25,685)	11,808	17,079
Proceeds from the sale of oil and natural gas properties	48,524	3,259	1,505
Advances to operators	(204)	776	994
Advances for joint operations	(2,076)	2,943	(229)
Other	(105)	(2,840)	(70)
Net cash used in investing activities	(162,453)	(555,345)	(227,724)
CASH FLOWS FROM FINANCING ACTIVITIES:			
Net proceeds from common stock issuances:			
Stock offerings, net of offering costs		135,075	71,926
Stock option exercises	9	262	1,031
Net proceeds from debt issuance and borrowings	128,113	778,182	174,000
Debt repayments	(96,461)	(498,923)	(108,258)
Payments of financing costs and other	(3,927)	(10,847)	(3,588)

Net cash provided by financing activities		27,734		403,749		135,111
NET INCREASE (DECREASE) IN CASH AND CASH EQUIVALENTS		(1,347)		(2,842)		2,618
CASH AND CASH EQUIVALENTS, beginning of year		5,184		8,026		5,408
CASH AND CASH EQUIVALENTS, end of year	$	3,837	$	5,184	$	8,026
SUPPLEMENTAL CASH FLOW DISCLOSURES:						
Cash paid for interest (net of amounts capitalized)	$	16,347	$	4,160	$	12,217
Cash paid for income taxes	$	67	$	30	$	

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., a Texas corporation (Carrizo or the Company) is an independent energy company engaged in the exploration, development and production of natural gas and oil, primarily in the Barnett Shale area in North Texas, the Marcellus Shale area in Appalachia and in proved onshore trends along the Texas and Louisiana Gulf Coast regions. The Company s other interests include properties in the U.K. North Sea.

2. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES
Principles of Consolidation

The consolidated financial statements are presented in accordance with U.S. generally accepted accounting principles. The consolidated financial statements include the accounts of the Company and its wholly-owned subsidiaries after elimination of all significant intercompany transactions and balances. The financial statements reflect necessary adjustments, all of which were of a recurring nature and are in the opinion of management necessary for a fair presentation.

Unconsolidated Investments

The Company accounts for its investment in Pinnacle Gas Resources, Inc. (Pinnacle) as available-for-sale and adjusts the book value to fair market value through other comprehensive income (loss), net of taxes. This fair value adjustment is assessed quarterly for other than temporary impairment based upon publicly available information. If the impairment is deemed other than temporary, it will be recognized in earnings. Subsequent recoveries in fair value are reflected as increases to the investment in other comprehensive income (loss).

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

Reclassifications

Certain reclassifications have been made to prior period amounts to conform to the current year presentation. These reclassifications had no effect on total assets, total liabilities, shareholders equity or net income (loss).

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 disclosure of contingent assets and liabilities at the date of the consolidated financial statements and the reported amounts of revenues and expenses during the periods reported. Actual results could differ from these estimates.

Significant estimates include volumes of oil and natural gas reserves used in calculating depletion of proved oil and natural gas properties, future net revenues and abandonment obligations, impairment of unproved properties, future taxable income and related assets/liabilities, the collectability of outstanding accounts receivable, fair values of derivatives, stock-based compensation expense, contingencies and the results of current and future litigation. Oil and natural gas reserve estimates which are the basis for unit-of-production depletion and the ceiling test, have numerous inherent uncertainties. The accuracy of any reserve estimate is a function of the quality of available data and of engineering and geological interpretation and judgment. Subsequent drilling results, testing and production may justify revision of such estimates. Accordingly, reserve estimates are often different from the quantities of oil and natural gas that are ultimately recovered. In addition, reserve estimates are vulnerable to changes in wellhead prices of crude oil and natural gas. Such prices have been volatile in the past and can be expected to be volatile in the future.

The significant estimates are based on current assumptions that may be materially affected by changes to future economic conditions such as the market prices received for sales of volumes of oil and natural gas, the creditworthiness of counterparties, interest rates, the market value of the Company s common stock and corresponding volatility and the Company s ability to generate future taxable income. Future changes in these assumptions may affect these significant estimates materially in the near term. The Company has also evaluated subsequent events for recording and disclosures, including assumptions used in its estimates.

Oil and Natural Gas Properties

Investments in oil and natural gas properties are accounted for using the full-cost method of accounting. All costs directly

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associated with the acquisition, exploration and development of oil and natural gas properties are capitalized. Such costs include lease acquisitions, seismic surveys, and drilling and completion equipment. The Company proportionally consolidates its interests in unincorporated joint ventures and oil and natural gas properties. The Company capitalized compensation costs and other costs of employees working directly on exploration activities of $5.6 million, $7.8 million and $4.5 million in 2009, 2008 and 2007, respectively. Maintenance and repairs are expensed as incurred.

Depreciation, depletion and amortization (DD&A) of proved oil and natural gas properties is based on the unit-of-production method using estimates of proved reserve quantities. The depletable base includes estimated future development costs and dismantlement, restoration and abandonment costs, net of estimated salvage values. The depletion rate per Mcfe for 2009, 2008 and 2007 was $1.55, $2.23 and $2.36, respectively. Under the full cost method of accounting, the depletion rate is the current period production as a percentage of the total proved oil and natural gas reserves. Total proved reserves include both proved developed and proved undeveloped reserves. The depletion rate is applied to the net book value of the oil and natural gas properties (excluding unproved properties, exploratory wells in progress and capitalized interest) and estimated future development costs less net salvage value to calculate the depletion expense.

Costs not subject to amortization include costs of unevaluated leaseholds, seismic costs associated with specific unevaluated properties and exploratory wells in progress. These costs are evaluated periodically for impairment on a property-by-property basis. If the results of an assessment indicate that the properties have been impaired, the amount of such impairment is determined and added to the proved oil and natural gas property costs subject to DD&A. Factors considered by management in its impairment assessment include drilling results by the Company and other operators, the terms of oil and natural gas leases not held by production, production response to secondary activities and available funds for exploration and development. The Company expects it will complete its evaluation of the properties representing the majority of its unproved property costs within the next two to five years. The Company also capitalized interest associated with its unproved properties of $19.7 million, $20.5 million and $11.7 million in 2009, 2008 and 2007, respectively.

Dispositions of oil and natural gas properties are accounted for as adjustments to capitalized costs with no gain or loss recognized, unless such adjustments significantly alter the relationship between capitalized costs and proved reserves. We have not had any transactions that significantly alter that relationship.

Capitalized costs, less accumulated amortization and related deferred income taxes, are limited to a ceiling-test based on the estimated future net revenues, discounted at 10% per annum, from proved oil and natural gas reserves, less estimated future expenditures to be incurred in developing and producing the proved reserves, less any related income tax effects. If net capitalized costs exceed this limit, the excess is charged to earnings. During the years ended December 31, 2009 and 2008, the Company recorded impairment charges of $338.9 million ($216.1 million net of tax) and $178.5 million ($116.0 million net of tax), respectively. For the first quarter of 2009, the Company elected to use a pricing date subsequent to the balance sheet date, as allowed by SEC guidelines in effect at the time, to measure the full cost ceiling test impairment. Using prices as of May 6, 2009, the Company incurred an impairment charge of $216.4 million ($138.0 million net of tax). Had the Company used prices in effect as of March 31, 2009, an impairment charge of $323.2 million ($206.1 million net of tax) would have been recorded for the first quarter of 2009. The option to use a pricing date subsequent to the balance sheet is no longer available to the Company effective December 31, 2009 due to the adoption of the new oil and natural gas reporting requirements as described below under Recently Adopted Accounting Pronouncements. During the fourth quarter of 2009, the Company recorded an additional impairment of $122.5 million ($78.1 million net of tax) based on the unweighted average oil and natural gas prices at the beginning of each month in the twelve-month period ending December 31, 2009 as required under the new oil and natural gas reporting requirements. Prices used in the ceiling test computation do not include the impact of hedges as the Company s hedges are treated as non-designated derivatives.

Depreciation of other property and equipment is provided using the straight-line method based on estimated useful lives ranging from five to 10 years.

Cash and Cash Equivalents

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

Revenue Recognition and Natural Gas Imbalances

The Company follows the sales method of accounting for revenue recognition and natural gas imbalances, which recognizes over and under lifts of natural gas when sold, to the extent sufficient natural gas reserves or balancing agreements are in place. Natural gas, natural gas liquids and oil sales volumes are not significantly different from the Company s share of production.

The Company purchases natural gas at the well head from a third-party operator under a purchase and sales agreement whereby the Company recognizes revenue at the redelivery point, which is the point at which title to the natural gas transfers to the purchaser. The Company then remits the sales proceeds received less a fixed fee per unit of production (MMBtu) transported which is recorded at the cost of the natural gas purchased.

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Deferred Financing Costs, net

Net long-term debt financing costs of $9.7 million (net of $3.9 million of accumulated amortization) and $8.4 million (net of $1.4 million of accumulated amortization) were capitalized as of December 31, 2009 and 2008, respectively, and are being amortized using the effective yield method over the term of the debt, which is through May 2013 for the Convertible Senior Notes and through October 2012 for the Senior Credit Facility.

Supplemental Cash Flow Information

The Statement of Cash Flows for the years ended December 31, 2009, 2008 and 2007 does not include the adjustment of the investment in Pinnacle of $0.2 million, $(6.7) million, and $5.4 million, respectively, net of tax.

Financial Instruments

The Company s financial instruments consist of cash, receivables, payables and long-term debt. The carrying amount of cash, receivables and payables approximates fair value because of the short-term nature of these items. The carrying amounts of long-term debt under the Senior Credit Facility approximate fair value as these borrowings bear interest at variable interest rates. The carrying amount of the Convertible Senior Notes does not approximate fair value because the notes are fixed rate debt.

Stock-Based Compensation

The Company s incentive plan authorizes the granting of stock options, including stock appreciation rights (SARs) that settle in the Company s common stock, and stock awards to directors, employees and independent contractors. The Company recognized the following stock-based compensation expenses for the periods indicated:

	Years Ended December 31,		
	2009	2008	2007
		(In millions)	
Stock Option and SARs	$ 1.2	$ 0.1	$ 0.3
Restricted Stock	10.1	5.9	4.6
Total Stock-Based Compensation	$ 11.3	$ 6.0	$ 4.9
Tax Benefit	$ 4.1	$ 2.1	$ 1.7

Stock Options and SARs. For stock options, including SARs that settle in common stock, compensation expense is based on the grant-date fair value of the option and recognized in equity at the grant date, and then expensed over the vesting period. Stock options typically expire ten years after the date of grant. SARs expire seven years after the date of grant. SARs that settle in cash are valued at each reporting period date and an expense and liability are recognized over the vesting period.

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

The risk-free interest rate is based on a Treasury bond at date of grant that corresponds to the expected term of the option/SAR.

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 market price volatility of the Company s common stock is based on daily, historical prices equal to the expected term of the option/SAR.

The term of the grants is based on the simplified method, or on historical experience.

Restricted Stock. The Company grants shares of restricted stock and measures deferred compensation based on the average of the high and low price of the Company s stock on the grant date. The deferred compensation is amortized to stock-based compensation expense ratably over the vesting period of the restricted shares (generally one to three years), using either the straight-line or graded vesting method. Restricted stock issued to independent contractors that vests over time as services are provided is adjusted to fair value at each reporting period with the change in fair value being recorded to expense over the requisite service period.

Taxes. Upon settlement of stock awards, the Company recognizes any difference between book compensation expense and tax compensation expense as a tax windfall or shortfall. The difference is charged to equity in the case of a windfall. In the case of shortfalls, the difference is charged to equity to the extent of previously recognized windfall tax benefits and any remaining shortfall is recognized as additional income tax expense. When the settlement of an award results in a net operating loss (NOL), or

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increases an NOL carryforward, no windfall is recognized until the deduction reduces income tax payable. At December 31, 2009, the Company had an NOL of approximately $94.9 million for tax purposes. For book purposes, the Company has deferred the recognition of approximately $13.2 million in windfall tax benefits associated with its stock-based compensation until a tax cash savings is realized.

Derivative Instruments

The Company uses derivatives, typically fixed-rate swaps, costless collars, puts, calls and basis differential swaps, to manage price risk underlying its oil and natural gas production. The Company also used derivatives to manage the variable interest rate on its second lien credit facility prior to its termination in May 2008.

Upon entering into a derivative contract, the Company either designates the derivative instrument as a hedge of the variability of cash flow to be received (cash flow hedge) or the derivative must be accounted for as a non-designated derivative. All of the Company s derivative instruments for the years ended December 31, 2009, 2008 and 2007 were treated as non-designated derivatives and the unrealized gain/(loss) related to the change in the fair value was included in the Company s earnings as gain (loss) on derivatives, net. The Company offsets fair value amounts recognized for derivative instruments executed with the same counterparty.

The Company s Board of Directors sets all risk management policies and reviews volume limitations, types of instruments and counterparties on a quarterly basis. These policies require that derivative instruments be executed only by either the President or Chief Financial Officer after consultation 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. The Board of Directors also reviews the status and results of derivative activities quarterly.

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 future taxable income based upon the Company s estimated production of proved reserves at estimated future pricing in making such assessments. 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.

Concentration of Credit Risk

Substantially all of the Company s accounts receivable result from oil and natural gas sales, joint interest billings to third parties in the oil and natural gas industry or drilling and completion advances to third-party operators for development costs of in-progress wells. 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 contracts subject the Company to a concentration of credit risk. At December 31, 2009, approximately 58% of the Company s open natural gas hedges were with Credit Suisse, 32% were with Shell Energy North America (US), L.P. and the remaining 10% were with Credit Agricole CIB. The Company maintains its cash with major U.S. banks and one bank in the United Kingdom. From time to time, cash amounts may exceed the FDIC insured limit of $250,000. The terms of these deposits are on demand to minimize risk. Historically, the Company has not incurred losses related to these deposits.

Allowance for Doubtful Accounts

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

January 1, 2007	$ 1,639
Charged to general and administrative expense	(209)

December 31, 2007	$ 1,430
Charged to general and administrative expense	(166)
December 31, 2008	$ 1,264
Charged to general and administrative expense	772
December 31, 2009	$ 2,036

Major Customers

The Company sold oil and natural gas production representing more than 10% of its oil and natural gas revenues as follows:

	Year Ended December 31,		
	2009	2008	2007
DTE Energy Trading, Inc.	54%	39%	*
Cokinos Natural Gas Company	*	11%	11%
Crosstex Energy	*	10%	15%
Houston Pipeline Company	*	*	11%
Energy Transfer	*	*	10%

(*) Revenues were below 10%.

Earnings Per Share

Supplemental earnings per share information is provided below:

	Year Ended December 31,		
	2009	2008	2007
	(In thousands, except per share amounts)		
Net income (loss) available to common shareholders	$ (204,845)	$ (45,047)	$ 15,469
Basic weighted average common shares outstanding	31,006	30,326	26,641
Stock options			479
Diluted weighted average shares outstanding	31,006	30,326	27,120
Earnings (loss) per share			
Basic	$ (6.61)	$ (1.49)	$ 0.58
Diluted	$ (6.61)	$ (1.49)	$ 0.57

Basic earnings (loss) per common share is based on the weighted average number of shares of common stock outstanding during the periods. Diluted earnings (loss) per common share is based on the weighted average number of common shares and all dilutive potential common shares outstanding during the periods. The Company had outstanding 1,205,770 and 685,854 stock options, stock-settled SARs and restricted stock units at December 31, 2009 and 2008, respectively, that were antidilutive due to the net loss for those periods. Shares subject to potential issuance upon conversion of the Convertible Senior Notes did not have any impact on the calculation for 2009 or 2008.

Contingencies

Liabilities and other contingencies are recognized upon determination of an exposure, when it is both probable that an asset has been impaired or that a liability has been incurred and that the amount of such loss is reasonably estimable.

Asset Retirement Obligation

The Company records asset retirement obligation (ARO) associated with the retirement of a long-lived asset as a liability in the period in which a legal obligation is incurred and becomes determinable, with an offsetting increase in the carrying amount of the associated asset. The ARO is recorded at fair value, excluding salvage values, and accretion expense will be recognized over time as the discounted liability is accreted to its expected settlement value. The fair value of the ARO is measured using expected future cash outflows discounted at the Company s credit-adjusted risk-free interest rate. The cost of the tangible asset, including the initially recognized ARO, is depleted such that the cost of the ARO is recognized over the useful life of the asset.

Inherent in the fair value calculation of ARO are numerous assumptions and judgments including the ultimate settlement amounts, inflation factors, credit adjusted discount rates, timing of settlement, and changes in the legal, regulatory, environmental and political environments. To the extent future revisions to these assumptions impact the fair value of the existing ARO liability, a corresponding adjustment is made to the oil and natural gas property balance. Settlements greater than or less than amounts accrued as ARO are recovered as a gain or loss upon settlement.

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The following table is a reconciliation of the asset retirement obligation liability for the years ended December 31:

	2009	2008
	(In thousands)	
Asset retirement obligation at beginning of year	$ 6,503	$ 5,869
Liabilities incurred	444	1,004
Liabilities settled	(36)	(177)
Accretion expense	308	154
Revisions to previous estimates	(1,809)	(347)
Asset retirement obligation at end of year	$ 5,410	$ 6,503

Foreign Currency

The company has foreign activities related to its investment in the U.K. North Sea. Transaction gains or losses that occur due to the realization of assets and the settlement of liabilities using a currency denominated in other than the functional currency are recorded as other income, net.

Recently Adopted Accounting Pronouncements

On January 1, 2009, the Company adopted new accounting guidelines related to convertible debt instruments that may be settled in cash (including partial cash settlement) upon conversion. Under the accounting guidelines, issuers of convertible debt are required to separately account for the liability and equity components in a manner that reflects the entity s nonconvertible debt borrowing rate when interest cost is recognized in subsequent periods. The new accounting guidelines require retrospective application to the terms of instruments as they existed for periods presented. The Company retrospectively applied the accounting guidelines to the Convertible Senior Notes. The Company valued the Senior Convertible Notes as $309.6 million of debt and $64.2 million of equity, representing the fair value of the conversion premium of the convertible debt at the date of issuance and accordingly restated its balance sheet as of December 31, 2008 for the carrying value of debt and equity and restated its results of operations for interest expense, capitalized interest, and income taxes for the year ended December 31, 2008.

On January 1, 2009, the Company adopted and retroactively applied new accounting guidelines related to restricted stock and participating securities. Under the new accounting treatment, unvested share-based payment awards that contain non-forfeitable rights to dividends or dividend equivalents, whether paid or unpaid, are participating securities and shall be included in the computation of both basic and diluted earnings per share. These new guidelines require retroactive application for all periods presented. The Company determined that its restricted shares of common stock are participating securities and applied the new accounting treatment retrospectively to all periods presented.

In March 2008, new guidance for derivative disclosures was issued and requires transparency about the location and amounts of derivative instruments in an entity s financial statements, how derivative instruments and related hedged items are accounted for, and how derivative instruments and related hedged items affect an entity s financial position, financial performance and cash flows. The Company adopted these requirements effective January 1, 2009. Since this guidance only impacted disclosure requirements, the adoption of this guidance did not have a significant effect on the Company s consolidated financial position, results of operations or cash flows.

On January 1, 2009, the Company adopted the guidance for non-financial assets and non-financial liabilities, except for items that are recognized or disclosed at fair value in the financial statements on a recurring basis, at least annually. The adoption of this guidance did not have a material impact on our financial position or results of operations.

In April 2009, guidance on the recognition of other-than-temporary impairments of investments in debt securities was issued. This pronouncement provides new presentation and disclosure requirements for other-than-temporary impairments of investments in debt and equity securities. The Company adopted the requirements of this pronouncement effective June 30, 2009, and it had no material impact on the Company s consolidated financial statements.

In April 2009, accounting rules were amended to require disclosure about fair value of financial instruments in interim reporting periods, as well as in annual financial statements. The Company adopted the requirements of this pronouncement effective June 30, 2009, and included the additional disclosures in the Company s notes to consolidated financial statements.

In May 2009, general standards of accounting for and disclosure of events that occur after the balance sheet date but before financial statements are issued were established to set forth: (1) the period after the balance sheet date during which management of a reporting entity should evaluate events or transactions that may occur for potential recognition or disclosure in the financial statements; (2) the circumstances under which an entity should recognize events or transactions occurring after the balance sheet date in its financial statements; and (3) the disclosures that an entity should make about events or transactions that occurred after the balance sheet date. The Company applied the requirement of this pronouncement effective June 30, 2009, and included additional disclosures in the Company s notes to consolidated financial statements. In February 2010, the Financial Accounting Standards Board (FASB) amended these standards to no longer require disclosure of the date through which management evaluated subsequent events in the financial statements.

In June 2009, the FASB established the Accounting Standards Codification (the Codification), which became effective July 1, 2009, as the single source of authoritative U.S. GAAP to be applied by nongovernmental entities. Rules and interpretive releases of the SEC under authority of federal securities laws are also sources of authoritative U.S. GAAP for SEC registrants. All other accounting literature excluded from the Codification will be considered non-authoritative. The subsequent issuances of new standards will be in the form of Accounting Standards Updates that will be included in the Codification. Generally, the Codification is not expected to change U.S. GAAP. The Company adopted the Codification effective September 30, 2009 and updated its disclosure references accordingly.

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 natural 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.

Additionally, the twelve month average pricing is required to be used to value future cash inflows in the standardized measure of discounted future net cash flows related to the Company s ownership interests in proved oil and natural gas reserves as of year-end 2009.

3. INVESTMENTS

Investments consisted of the following at December 31, 2009 and 2008:

	December 31, 2009	December 31, 2008
	(In thousands)	
Pinnacle Gas Resources, Inc.	$ 835	$ 751
Oxane Materials, Inc.	2,523	2,523
	$ 3,358	$ 3,274

Pinnacle Gas Resources, Inc.

In 2003, the Company and its wholly-owned subsidiary CCBM, Inc. contributed their interests in certain natural gas and oil leases in Wyoming and Montana in areas prospective for coalbed methane to a newly formed entity, Pinnacle Gas Resources, Inc. (Pinnacle).

In June 2007, the Company sold 41,894 shares of Pinnacle stock for net proceeds of $0.4 million and recognized a $0.3 million gain, which is included in other income and expenses, net on the Consolidated Statements of Operations. At March 31, 2009, the market value of the Company s investment in Pinnacle had consistently remained below its original book basis since October 2008. The Company determined that the impairment was other than temporary, and accordingly, recorded an impairment expense of $2.1 million at March 31, 2009. At December 31, 2009, the Company reported the fair value of the stock at $0.8 million (based on the closing price of Pinnacle s common stock on December 31, 2009).

On February 23, 2010, Pinnacle entered into an Agreement and Plan of Merger (the Merger Agreement) with affiliates of Scotia Waterous (USA), Inc. At the closing of the transactions contemplated by the Merger Agreement, Pinnacle is expected to be owned by an investor group led by Scotia Waterous (USA), Inc., which includes DLJ Merchant Banking Partners III, L.P. and affiliated investment funds and certain members of Pinnacle s management team.

Subject to the terms and conditions of the Merger Agreement, at the effective time and as a result of the Merger, each outstanding share of Pinnacle common stock, (other than dissenting shares and those owned by the buyers and affiliates) will be converted into the right to receive a cash amount of $0.34 per share. As of December 31, 2009, the Company owned 2,529,354 shares of Pinnacle common stock.

Oxane Materials, Inc.

In May 2008, the Company entered into a strategic alliance agreement with Oxane Materials, Inc. (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.

4. PROPERTY AND EQUIPMENT

At December 31, 2009 and 2008, property and equipment consisted of the following:

	December 31,	
	2009	2008
	(In thousands)	
Proved oil and natural gas properties	$ 667,907	$ 821,238
Costs not subject to amortization	330,607	378,634
Land, building and other equipment	6,475	6,363
Total property and equipment	1,004,989	1,206,235
Accumulated depreciation, depletion and amortization	(271,289)	(219,606)
Property and equipment, net	$ 733,700	$ 986,629

Costs not subject to amortization include the cost of unevaluated leaseholds and seismic costs associated with specific unevaluated properties of $258.3 million, exploratory wells in progress of $37.7 million and capitalized interest of $34.6 million. At December 31, 2009, approximately $86.2 million, $224.1 million, $5.9 million and $14.4 million were incurred in 2009, 2008, 2007 and earlier years, respectively.

The significant decline in oil and natural gas prices beginning in mid-2008 and the continued depressed price of natural gas in 2009 caused the discounted present value (discounted at 10 percent) of future net cash flows from proved oil and gas reserves to fall below the net book basis of the proved oil and gas properties. This resulted in non-cash ceiling test write-downs of $122.5 million ($78.1 million after tax) at the end of the fourth quarter of 2009, $216.4 million ($138.0 million after tax) at the end of the first quarter 2009, and $178.5 million ($116.0 million after tax) at the end of the fourth quarter of 2008.

The Company sold its Mansfield pipeline and gathering system in the Barnett Shale to Delphi Midstream Partners, LLC (Delphi) for net proceeds of $34.7 million during the fourth quarter of 2009.

In December 2009, the Company entered into a strategic alliance with a subsidiary of Sumitomo Corporation (Sumitomo). The Company sold Sumitomo a 12.5% working interest in 16 drilling units in the Barnett Shale for $15.7 million for certain costs previously incurred by the Company with respect to these drilling units, including Sumitomo s proportionate share of certain land seismic and drilling costs.

5. INCOME TAXES

All of the Company s income is derived from domestic activities. Actual income tax expense (benefit) differs from income tax expense (benefit) computed by applying the U.S. federal statutory corporate rate of 35% to pretax income as follows:

	Year Ended December 31,		
	2009	2008	2007
		(In thousands)	
Provision at the statutory tax rate	$ (111,353)	$ (23,020)	$ 8,649
State taxes, net of federal benefit	(2,270)	123	594

Nondeductible expenses	35	1,930	
Other	281	242	
Income tax expense (benefit)	$ (113,307)	$ (20,725)	$ 9,243

Substantially all of the income tax expense (benefit) is deferred for the years ended December 31, 2009, 2008 and 2007.

Deferred income taxes result from temporary differences in the recognition of income and expenses for financial reporting purposes and for tax purposes. At December 31, 2009 and 2008, the tax effects of these temporary differences resulted principally from the following:

	December 31, 2009	December 31, 2008
	(In thousands)	
Deferred income tax assets:		
Net operating loss carryforward	$ 29,629	$ 23,547
Financial Statement DD&A and impairment charges in excess of oil an gas acquisition, exploration and development costs deducted for tax purposes	84,919	
Stock based compensation	1,963	1,549
Allowance for doubtful accounts	738	442
Equity in loss of Pinnacle	399	385
Valuation allowance	(399)	(385)
Adjustment to fair value of investment in Pinnacle	707	699
Other	224	
	118,180	26,237
Deferred income tax liabilities:		
Oil and gas acquisition, exploration and development costs deducted for tax purposes in excess of financial statement DD&A		12,740
Conversion premium on convertible debt	16,352	20,044
Capitalized interest	30,455	22,520
Fair value derivative instruments	2,630	14,659
Other		155
	49,437	70,118
Net deferred income tax asset (liability)	$ 68,743	$ (43,881)

At December 31, 2009 and 2008, the net deferred income tax liability is classified as follows:

	December 31, 2009	December 31, 2008
	(In thousands)	
Noncurrent deferred tax asset	$ 70,217	$
Current deferred tax liability	(1,474)	(9,103)
Noncurrent deferred tax liability		(34,778)
Deferred income tax asset (liability), net	$ 68,743	$ (43,881)

As of December 31, 2009, the Company had income tax NOL carryforwards of approximately $94.9 million which expire from 2019 through 2029. The realization of the deferred tax assets related to the NOL carryforwards is dependent on the Company s ability to generate taxable income in the future. The Company believes it will be able to generate sufficient taxable income in the NOL carryforward period. As such, management believes that it is more likely than not that its deferred tax assets, other than the deferred tax asset attributable to Pinnacle, will be fully realized. A full valuation allowance has been established for the equity in loss of Pinnacle s tax asset as the realization of the deferred tax asset is dependent on generating sufficient taxable income in the future, which management believes is unlikely.

The ability of the Company to utilize NOL carryfowards to reduce future taxable income is subject to various limitations under the Internal Revenue Code of 1986, as amended. The utilization of such carryfowards 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, 2009, we believe an ownership change occurred in February 2005 with an annual limitation of approximately $12.6 million. 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 NOL carryforwards as of December 31, 2009. Future equity transactions involving the Company or 5% shareholders of the Company (including, potentially, relatively small transactions and transactions beyond our control) could cause further ownership changes and therefore a limitation on the annual utilization of NOLs.

The Company classifies interest and penalties associated with income taxes as interest expense. At December 31, 2009, 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.

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6. LONG-TERM DEBT

At December 31, 2009 and 2008, long-term debt consisted of the following:

	December 31,	
	2009	2008
	(In thousands)	
Convertible Senior Notes	$ 373,750	$ 373,750
Unamortized discount for Convertible Senior Notes	(45,122)	(57,269)
Senior Secured Revolving Credit Facility	191,400	159,000
Other	308	480
	520,336	475,961
Less: current maturities	(148)	(173)
	$ 520,188	$ 475,788

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 will be convertible, using a net share settlement process, into a combination of cash and Carrizo 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.

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 the Senior Credit Facility (defined below), the occurrence and continuation of which could result in the acceleration of amounts due under the Convertible Senior Notes. The Company is currently in compliance with the provisions of the Convertible Senior Notes.

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

In accordance with the accounting guidelines for convertible debt, 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 will be 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, which will result in an effective interest rate of approximately 8% for the Convertible Senior Notes. Amortization of the debt discount amounted to $12.1 million and $6.9 million for the years ended December 31, 2009 and 2008, respectively.

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Senior Secured Revolving Credit Facility

The Company has a senior secured revolving credit facility (the Senior Credit Facility) with Wells Fargo Bank, N.A., as administrative agent. The Senior Credit Facility provides for a revolving credit facility up to the lesser of the borrowing base and $350.0 million. It is secured by substantially all of the Company s proved oil and gas assets and is currently guaranteed by certain of the Company s subsidiaries: CCBM, Inc.; CLLR, Inc.; Carrizo (Marcellus), LLC; Carrizo Marcellus Holdings, Inc.; Hondo Pipeline Inc.; Bandelier Pipeline Holding, LLC and Mescalero Pipeline, LLC.

The Senior Credit Facility matures on October 29, 2012, and is subject to semi-annual borrowing base redetermination dates on March 31 and September 30.

In April 2009, the Company amended the Senior Credit Facility to, among other things, (1) adjust the maximum ratio of total net debt to Consolidated EBITDAX; (2) modify the calculation of total net debt for purposes of determining the ratio of total net debt to Consolidated EBITDAX to exclude the following amounts, which represent a portion of the Convertible Senior Notes deemed to be an equity component under the accounting guidelines related to convertible debt that may be settled in cash (including partial cash settlement) upon conversion: $51.3 million during 2009, $38.9 million during 2010, $26.0 million during 2011 and $12.7 million during 2012 until the maturity date; (3) add a new senior leverage ratio; (4) modify the interest rate margins applicable to Eurodollar loans; (5) modify the interest rate margins applicable to base rate loans; and (6) establish new procedures governing the modification of swap agreements.

In May 2009, the Company amended the Senior Credit Facility to, among other things, (1) provide that the aggregate notional volume of oil and natural gas subject to swap agreements may not exceed 80% of forecasted production from proved producing reserves, (as that term is defined in the Senior Credit Facility), for any month, (2) remove a provision that limited the maximum duration of swap agreements permitted under the Senior Credit Facility to five years, and (3) provide that the aggregate notional amount under interest rate swap agreements may not exceed the amount of borrowings then outstanding under the Senior Credit Facility.

If the outstanding principal balance of the revolving loans under the Senior Credit Facility exceeds the borrowing base at any time, 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, pledge additional collateral 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 ensuing six-month period. Those payments would be in addition to any payments that may come due as a result of the quarterly borrowing base reductions. Otherwise, any unpaid principal or interest 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 Base CD Rate plus 1.0% and the Federal Funds Effective Rate plus 0.5%, plus (b) a margin between 1.00% and 2.00% (depending on the then-current level of borrowing base usage), but such interest rate can never be lower than the adjusted Daily LIBO rate on such day plus a margin between 2.25% to 3.25% (depending on the current level of borrowing base usage). The interest rate on each Eurodollar loan will be the adjusted daily LIBO rate plus a margin between 2.25% to 3.25% (depending on the then-current level of borrowing base usage). At December 31, 2009, the average interest rate for amounts outstanding under the Senior Credit Facility was 3.1%.

The Company is subject to certain covenants under the amended terms of the Senior Credit Facility which include, but are not limited to, the maintenance of the following financial ratios: (1) a minimum current ratio of 1.00 to 1.00 (as defined in the Senior Credit Facility); and (2) a maximum total net debt to Consolidated EBITDAX (as defined in the Senior Credit Facility) of (a) 4.75 to 1.00 for each quarter ending on or after December 31, 2009 and on or before September 30, 2010, (b) 4.25 to 1.00 for the quarter ending December 31, 2010, and (c) 4.00 to 1.00 for each quarter ending on or after March 31, 2011; and (3) a maximum ratio of senior debt (which excludes certain amounts attributable to the Convertible Senior Notes) to Consolidated EBITDAX of 2.25 to 1.00.

The Senior Credit Facility also places restrictions on indebtedness, dividends to shareholders, liens, investments, mergers, acquisitions, asset dispositions, repurchase or redemption of our common stock, speculative commodity transactions, transactions with affiliates and other matters. The Company is currently in compliance with the provisions of the Senior Credit Facility.

The Senior Credit Facility is subject to customary events of default, the occurrence and continuation of which could result in the acceleration of amounts due under the facility by the agent or the lenders.

At December 31, 2009, the Company had $191.4 million of borrowings outstanding under the Senior Credit Facility, and the amount available for borrowings was $158.6 million which can be used to fund working capital and the Company s capital expenditure plan to the extent such amounts exceed the cash flow from operations.

7. 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 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.

The Company has a long-term operating lease agreement for its corporate offices that expires in December 2011. Under the terms of the lease agreement, the Company received a rent abatement equal to six months of lease payments and a build out allowance that is being amortized to expense over the term of the lease. In July 2006, the Company amended its lease agreement to expand the leased office space by an additional floor. The lease term for the additional floor also expires in December 2011. Rent expense for the years ended December 31, 2009, 2008 and 2007 was $0.9 million, $0.9 million and $0.9 million, respectively, and includes rent expense for the Company s corporate office and a field office in the Barnett Shale area.

Minimum office rentals, drilling rig obligations and pipeline volume commitments for each of the five years subsequent to December 31, 2009 are as follows (in thousands):

	Amount (in thousands)
2010	$ 35,985
2011	17,524
2012	7,019
2013	6,556
2014 and Thereafter	15,504
	$ 82,588

8. SHAREHOLDERS EQUITY AND STOCK INCENTIVE PLAN

Shareholders Equity

In February 2008, the Company completed an underwritten public offering of 2.6 million shares of its common stock at a price of $54.50 per share. The Company received proceeds of approximately $135.1 million, net of expenses, which were used to repay $85.0 million of outstanding borrowings under the Senior Credit Facility and fund a portion of the Company s 2008 capital expenditure program.

In September 2007, the Company sold 1.8 million shares of its common stock to certain qualified investors in a registered direct offering at a price of $41.40 per share. The Company received proceeds of approximately $71.9 million, net of expenses, which were used to repay $54 million of outstanding borrowings under the Senior Credit Facility and fund a portion of the Company s 2007 capital expenditure program.

Stock Incentive Plan

The Company s incentive plan authorizes the granting of stock options, including SARs that settle in the Company s common stock, and stock awards to directors, employees and independent contractors. The Company may grant awards of up to 4,395,000 shares under the Incentive Plan and has granted options, restricted stock and restricted stock units covering 3,294,463 shares through December 31, 2009, net of forfeitures.

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Stock Options and SARs. The table below summarizes stock option and SAR activity for the three years ended December 31, 2009:

	Shares	Weighted-Average Exercise Prices	Weighted-Average Remaining Life (In years)	Aggregate Intrinsic Value (In millions)
For the Year Ended December 31, 2007				
Outstanding, beginning of period	891,069	$ 5.25		
Granted				
Exercised	(124,148)	8.30		
Forfeited	(5,000)	16.35		
Outstanding, end of period	761,921	$ 4.67		
Exercisable, end of period	731,808	$ 4.23		
For the Year Ended December 31, 2008				
Outstanding, beginning of period	761,921	$ 4.67		
Granted				
Exercised	(65,400)	4.01		
Forfeited	(10,667)	6.72		
Outstanding, end of period	685,854	$ 4.71		
Exercisable, end of period	685,854	$ 4.71		
For the Year Ended December 31, 2009				
Outstanding, beginning of period	685,854	$ 4.71		
Granted	214,609	20.18		
Exercised	5,000	1.81		
Outstanding, end of period	895,463	$ 8.43	3.8	$ 16.6
Exercisable, end of period	680,854	$ 4.73	2.0	$ 15.1

At December 31, 2009, the Company had $1.4 million of unrecognized expense associated with nonvested stock option and SAR awards. The total intrinsic value (current market price less the option/SAR strike price) of options and SARs exercised during the years ended December 31, 2009, 2008 and 2007 was $0.1 million, $2.5 million and $4.5 million, respectively, and the Company received approximately $9,000, $0.3 million and $1.0 million in cash in connection with option exercises for the years ended December 31, 2009, 2008 and 2007, respectively.

During 2009, the Company granted SARs with a weighted average grant-date fair value of $10.10 per option based on (1) a weighted average risk-free rate of 2.0%, (2) a zero dividend yield rate, (3) an expected volatility rate of 61.3% and (4) a weighted average expected term of 4.1 years. These grants included performance and service conditions that were satisfied during the fourth quarter of 2009.

Restricted Stock Shares and Units. The Company began issuing shares of restricted common stock in 2005 and restricted stock units in 2008. A restricted stock unit is an obligation to issue shares of stock upon their vesting.

Unvested restricted stock awards are deemed issued and outstanding based on the terms of the award. Restricted stock shares and units are accounted for as deferred compensation based on the closing price of the Company s common stock on the grant date and are amortized to stock-based compensation expense over the vesting period (generally one to three years). The unamortized deferred compensation obligation amounted to $7.4 million as of December 31, 2009 and is expected to be expensed over the next two years. The table below summarizes restricted stock activity for the three years ended December 31, 2009:

	Shares/ Units	Grant-date Fair Value
Unvested restricted stock at December 31, 2006	326,209	$ 25.87
Granted	132,719	40.26
Vested	(86,199)	25.13
Forfeited	(20,880)	31.21
Unvested restricted stock at December 31, 2007	351,849	31.15
Granted	215,469	35.43
Vested	(217,113)	28.65
Forfeited	(8,507)	42.00
Unvested restricted stock 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 at December 31, 2009	471,243	$ 25.01

Included in the 2008 and 2009 grants of restricted stock shares and units were awards granted to key employees that contained performance and service conditions. The performance condition has 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 (CSAR) Plan (CSAR Plan). The CSAR Plan enables key employees and independent contractors to share in the appreciation of Carrizo s common stock. During 2009, the Company issued 80,262 CSARs. The CSARs when vested and exercised will be settled in cash. As such, the projected settlement is adjusted each reporting period based upon an updated Black-Scholes option pricing model, adjusted for the ending fair market value of Carrizo s common stock. At December 31, 2009, the Company recorded a liability of $0.4 million associated with the CSARs.

9. RELATED-PARTY TRANSACTIONS

Marcellus Shale Joint Venture. Effective as of August 1, 2008, a wholly-owned subsidiary Carrizo (Marcellus) LLC entered into a joint venture arrangement with an affiliate of Avista Capital Holdings, LP, a private equity fund (Avista). Under the terms of the joint venture, the Company and Avista each committed to contribute up to $150 million in cash and properties to acquire and develop acreage within an area of mutual interest located in the Marcellus Shale play, including the dedication of all of their respective Marcellus leasehold owned at the time of the formation of the joint venture.

The Company serves as operator of the joint venture with Avista under a joint operating agreement with Avista and provides all geotechnical, land, engineering and accounting support to the joint venture. The Company has also agreed to perform specified management services for the Avista affiliate that is the Company s partner in the joint venture on the same cost and reimbursement bases provided for in the joint operating agreement. An operating committee composed of one representative of each party provides overall supervision and direction of joint operations. Each representative has a vote equal to the participating interest in the properties and operations of the party it represents. 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.

Under the terms of the joint venture, each party committed to contribute up to $150 million in cash and properties to acquire and develop acreage in the Marcellus Shale play, including the dedication of all of its Marcellus Shale leasehold owned at the time of the formation of the joint venture. In connection with formation of the joint venture, Avista contributed certain leasehold interests (costing approximately $27.5 million) and agreed to fund 100% of the joint venture s next approximately $71.5 million of expenditures related to the Marcellus Shale play (the Initial Cash Contribution). Until mid-2009, Avista was required to fund substantially all of the joint venture s capital and exploration obligations and general and administrative expenses. Since that time, the Company and Avista have each borne equal shares of all costs of the joint venture operation in accordance with the participating interest, which to date remains 50/50.

Subject to specified exceptions, net cash flow from hydrocarbon production from the Marcellus joint venture properties and related sales proceeds, if the properties are sold, will be allocated first to the joint venture partners in proportion to their respective investments (with property dedications generally valued on a cost basis) until Avista has recovered its investment, then 100% to the Company until it recovers approximately $33.5 million, and thereafter in accordance with the parties participating interests, which the Company expects will generally be 50/50. The Company has also 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 addition to the Company s share in the production and sale proceeds from joint venture properties, the Company also acquired as part of the transaction (through a wholly-owned subsidiary) an interest in the Avista joint venture entity that entitles the Company to increasing percentages of the Avista entity s profits if that entity s members receive a return of their investment and specified internal rates of return on these investments are achieved. The Company s interest in the Avista entity provides consent rights only in limited, specified circumstances and generally does not entitle the Company to vote or participate in the management of the Avista entity, which is controlled by its members and affiliates.

As part of the transaction, and subject to certain exceptions, the parties agreed to enter into an area of mutual interest covering the Marcellus Shale play, wherein any lease, royalty or mineral rights acquired by one party within the area must be proportionately offered to the other on the same terms and conditions. The area of mutual interest 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: (1) December 31, 2010, (2) the date on which the parties collective investment reaches $300 million, (3) upon Avista s request to be designated (or have its designee designated) as a co-operator of the properties in connection with the sale to an unaffiliated third party of all of its membership interests or substantially all of its assets and (4) upon the required designation of Avista (or its designee) as a co-operator of the properties in connection with the Company s default under the terms of any pledge of the Company s interest in the properties.

The parties have limited rights to transfer their respective interests in the properties until the Initial Cash Contribution has been satisfied. After that time, each party s ability to transfer its interest in the joint venture to third parties is 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. Avista s tag along rights do not apply upon a change of control of Carrizo.

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. As previously disclosed, the Company has been a party to prior arrangements with affiliates of Avista Capital Holdings, LP in respect of the Company s investment in Pinnacle Gas Resources, Inc.

Avista Land Bank Agreement. In order to expand the Company s lease acquisition efforts in the Marcellus Shale play, the Company elected to enter into a lease option agreement effective August 1, 2008 with Avista, the Company s partner in the Marcellus Shale play. The terms and conditions of the lease purchase option arrangement with Avista were generally consistent with lease option arrangements that the Company has traditionally entered into with other third parties. Avista paid approximately $27.5 million for the oil and gas leases under the lease purchase option agreement and subsequently contributed these properties at their cost to the Company s Marcellus joint venture, effective August 1, 2008.

Other Transactions. The Company s Chairman of the Board, Mr. Steven A. Webster, serves on the Board of Directors for Basic Energy Services, Inc., Hercules Offshore, Inc., Pinnacle Gas Resources, Inc. and Geokinetics, Inc., the parent of Quantum Geophysical, Inc., and previously served on the Board of Directors of each of Goodrich Petroleum, Brigham Exploration and Grey Wolf Inc. The Company s Chief Executive Officer, Mr. S.P. Johnson, serves as member on the Board of Directors of Basic Energy Services, Inc. and Pinnacle Gas Resources, Inc. Mr. Thomas L. Carter, Jr., a member of the Company s Board of Directors, is the Chief Executive Officer and owner of a significant interest in Black Stone Minerals Company, L.P. (Black Stone Minerals). Mr. F. Gardner Parker serves on the Board of Directors for Hercules Offshore, Inc. Due to these relationships, the Company has deemed these companies to be related parties. The Company incurred the following costs with these related parties:

	Year Ended December 31,		
	2009	**2008**	**2007**
		(In millions)	
Basic Energy Services	$0.1	$0.4	$ 0.2
Geokinetics, Inc.	0.4		
Grey Wolf Inc.[1]		7.1	6.8
Brigham Exploration[2]			(0.3)
Hercules Offshore, Inc.		3.2	

(1) During 2009, Grey Wolf Inc. merged with another company and is no longer considered a related party at January 1, 2009.

(2) At the end of the first quarter of 2007, Mr. Webster resigned from the Board of

Directors of Goodrich Petroleum and Brigham Exploration. As such, these companies are no longer deemed related parties after the first quarter of 2007.

It is management s opinion that the transactions with these entities were executed at prevailing market rates. At December 31, 2009, 2008 and 2007, the Company had outstanding related-party net payable balances of approximately $66,000, $66,000 and $22,000, respectively.

In January 2006, the Company acquired certain oil and gas leases for approximately $1.1 million from Black Stone Acquisitions Partners I L.P., the general partner of which is Black Stone Minerals. Black Stone Acquisition Partners also retains a royalty interest in the acquired leases, which are located in Mississippi. During 2007, the Company acquired additional acreage located in Texas from Black Stone Minerals for approximately $0.2 million. During 2009 and 2008, the Company did not acquire any additional acreage from Black Stone Minerals. The terms and conditions of the lease agreement with Black Stone Acquisitions Partners I L.P. and Black Stone are generally consistent with the lease agreements that the Company has entered into with other third parties. Additionally, the Company operates four producing wells in which affiliates of Black Stone Minerals hold a royalty interest for which the Company paid approximately $0.2 million, $0.6 million and $0.8 million in 2009, 2008 and 2007, respectively.

We paid Mr. Webster less than $1,000 in each of 2009, 2008 and 2007 in overriding royalties that were incurred under a lease purchase option arrangement that expired in 2006.

Mr. Webster is also Co-Managing Partner and President of Avista Capital Holdings, L.P. and is therefore a related party to the Pinnacle transaction. See Note 3 for a discussion of the investment in Pinnacle.

10. DERIVATIVE FINANCIAL INSTRUMENTS

The Company typically uses fixed-rate swaps, costless collars, puts, calls and basis differential swaps to manage price risk associated with a portion of anticipated future oil and natural gas production. While the use of derivative financial instruments limits the downside risk of adverse price movements, it may also limit future gains from favorable movements. Under these agreements, 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 enters into the majority of its derivative transactions with three counterparties and netting agreements are in place with those counterparties. The Company does not obtain collateral to support the agreements but monitors the financial viability of counterparties and believes its credit risk is minimal on these transactions. In the event of nonperformance, the Company would be exposed to price and credit risk. The Company has some risk of accounting loss since the price received for the product at the actual physical delivery point may differ from the prevailing price at the delivery point required for settlement of the financial instruments. The Company used interest rate swap agreements to manage the Company s exposure to variable interest rates on borrowings under its second lien credit facility, which was terminated during 2008.

The Company accounts for its oil and natural gas derivatives and interest rate swap agreements as non-designated hedges. These derivatives are marked-to-market at each balance sheet date and the unrealized gains (losses) are reported in the gain (loss) on derivatives, net in the Consolidated Statements of Operations. In addition, the Company records the realized gains (losses) associated with the cash settlements of these derivative instruments in gain (loss) on derivatives, net in the Consolidated Statements of Operations. For the years ended December 31, 2009, 2008 and 2007, the Company recorded the following related to its derivatives:

	Year Ended December 31,		
	2009	**2008**	**2007**
		(In millions)	
Realized gain (loss)			
Natural gas and oil derivatives	$ 74.9	$ (1.9)	$ 6.4
Interest rate swaps		(1.2)	0.2
Loss on interest rate swap termination		(3.3)	
	74.9	(6.4)	6.6
Unrealized gain (loss)			
Natural gas and oil derivatives	(33.4)	41.1	(5.2)
Interest rate swaps		2.8	(2.8)
	(33.4)	43.9	(8.0)
Gain (loss) on derivatives, net	$ 41.5	$ 37.5	$ (1.4)

In 2009, the Company purchased certain hedge positions and deferred the payment of the premium of $4.8 million until settlement of the hedge position. At December 31, 2009, $1.8 million is classified as other-current liabilities and $3.0 million is classified as other non-current liabilities.

At December 31, 2009 the Company had the following open derivative positions:

	Natural Gas Swaps		Natural Gas Collars		
Quarter	**MMbtus(1)**	**Average Fixed Price(2)**	**MMbtus(1)**	**Average Floor Price(2)**	**Average Ceiling Price(2)**
First Quarter 2010	4,140,000	$5.51	2,070,000	$7.29	$8.96
Second Quarter 2010	4,641,000	5.52	1,092,000	5.50	6.99
Third Quarter 2010	3,496,000	5.75	1,564,000	5.76	7.31

Fourth Quarter 2010	3,036,000	5.83	1,840,000	6.12	7.57
First Quarter 2011	2,430,000	5.92	1,080,000	7.84	9.84
Second Quarter 2011	1,820,000	5.64	455,000	7.75	9.75
Third Quarter 2011	2,208,000	5.74	828,000	7.55	9.40
Fourth Quarter 2011	2,208,000	5.77	736,000	7.88	9.83
First Quarter 2012	1,365,000	6.22	1,001,000	8.04	9.96
Second Quarter 2012	910,000	5.88	455,000	7.80	9.80
Third Quarter 2012	1,472,000	6.06	644,000	6.41	7.91
Fourth Quarter 2012	1,472,000	6.09	644,000	6.48	8.43
TOTAL	29,198,000		12,409,000		

(1) During 2009, the Company entered into (1) a $5.00 put, a $5.85 long-call and an $7.65 short-call with respect to a portion of the Company s production hedged with swaps (10,000 MMBtus per day) in 2011, (2) a $5.05 put, a $5.90 long-call and a $7.70 short call with respect to a portion of the Company s production hedged with swaps (10,000 MMBtus per

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day) in 2012 and (3) a $3.93 put, a $5.58 long-call and a $6.08 short-call with respect to a portion of the Company s production hedged with swaps (20,000 MMBtus per day) for April through October of 2010.

The table below presents additional put positions the Company has entered into associated with a portion of hedged volumes presented above:

Quarter	MMBtus	Put Price
Second Quarter 2010	455,000	$3.74
Third Quarter 2010	920,000	4.31
Fourth Quarter 2010	1,196,000	4.61
First Quarter 2011	1,530,000	5.53
Second Quarter 2011	910,000	5.65
Third Quarter 2011	1,288,000	5.59
Fourth Quarter 2011	1,196,000	5.58
First Quarter 2012	1,911,000	5.46
Second Quarter 2012	1,365,000	5.45
Third Quarter 2012	1,564,000	4.97
Fourth Quarter 2012	1,564,000	4.98

(2) Based on Houston Ship Channel (HSC) and WAHA spot prices.

In addition, the Company sold the following natural gas long put positions:

Quarter	MMBtus	Average Fixed Price
Second Quarter 2010	300,000	$ 5.86
Third Quarter 2010	920,000	5.86
Fourth Quarter 2010	920,000	5.86
First Quarter 2011	900,000	5.80
Second Quarter 2011	910,000	5.80
Third Quarter 2011	920,000	5.80
Fourth Quarter 2011	920,000	5.80

The fair value of the outstanding oil and natural gas derivatives at December 31, 2009 and 2008 was an asset of $12.1 million and $38.7 million, respectively.

At December 31, 2009, approximately 58% of the Company s open natural gas hedges were with Credit Suisse, 32% were with Shell Energy North America (US), L.P. and the remaining 10% were with Credit Agricole CIB.

During the first and second quarter of 2007, the Company entered into interest swap agreements covering amounts outstanding under its second lien credit facility. These arrangements were designed to manage the Company s exposure to variable interest rates through December 31, 2008 by effectively exchanging existing obligations to pay interest based on floating rates with obligations to pay interest based on fixed LIBOR. In connection with the Company s repayment of borrowings under and termination of the second lien credit facility, following the issuance of the Convertible Senior Notes in May 2008, the remaining open derivative positions on interest rates were cash settled, resulting in a realized loss of $3.3 million on the remaining positions covering the period from May 28, 2008 to December 31, 2008.

11. 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.

The following table presents information about the Company s assets and liabilities measured at fair value on a recurring basis as of December 31, 2009, and indicates the fair value hierarchy of the valuation techniques utilized by the Company to determine such fair value:

	Level 1	Level 2	Level 3	Total
		(In thousands)		
Assets:				
Investment in Pinnacle Gas Resources, Inc.	$ 835	$	$	$ 835
Oil and natural gas derivatives		14,881		14,881
Liabilities:				
Oil and natural gas derivatives		(2,818)		(2,818)
Total	$ 835	$ 12,063	$	$ 12,898

Oil and natural gas derivatives are valued by a third-party consultant using valuation models that are primarily industry-standard models that consider various inputs including: (a) quoted forward prices for commodities, (b) time value, (c) volatility factors and (d) current market and contractual prices for the underlying instruments, as well as other relevant economic measures.

Fair Value of Other Financial Instruments

The Company s other financial instruments consist of cash and cash equivalents, accounts receivable, accounts payable and bank borrowings, including borrowings under the Senior Credit Facility. The carrying amounts of cash and cash equivalents, accounts receivable and accounts payable approximate fair value due to the highly liquid nature of these short-term instruments. The fair values of the bank and vendor borrowings approximate the carrying amounts as of December 31, 2009 and 2008, and were determined based upon interest rates currently available to the Company for borrowings with similar terms. The fair value of the Convertible Senior Notes at December 31, 2009 was estimated at approximately $321.7 million based on a quote provided by an investment bank.

12. SUPPLEMENTARY FINANCIAL INFORMATION ON OIL AND NATURAL GAS EXPLORATION, DEVELOPMENT AND PRODUCTION ACTIVITIES (UNAUDITED)

The following disclosures provide unaudited information regarding oil and natural gas activities.

Costs Incurred

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

	Year Ended December 31,		
	2009	2008	2007
		(In thousands)	
Property acquisition costs			
Unproved	$ 35,248	$ 271,618	$ 54,467
Proved			
Exploration costs	77,255	235,382	144,402
Development costs	55,270	49,626	30,562
Asset retirement obligation	(1,390)	630	1,961
Total costs incurred[1]	$ 166,383	$ 557,256	$ 231,392

(1) Excludes capitalized

interest on unproved properties of $19.7 million, $20.5 million, and $11.7 million for the years ended December 31, 2009, 2008 and 2007, respectively, and includes capitalized overhead of $5.6 million, $7.8 million, and $4.5 million for the years ended December 31, 2009, 2008 and 2007, respectively.

Oil And Natural Gas Reserves

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.

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Proved oil and natural gas reserve quantities at December 31, 2009, 2008 and 2007, 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 & Stan. Such estimates have been prepared in accordance with guidelines established by the Securities and Exchange Commission.

The Company s net ownership interests in estimated quantities of proved oil and natural gas reserves and changes in net proved reserves, all of which are located in the continental United States, are summarized below:

	Millions of Cubic Feet of Natural Gas at December 31,		
	2009	2008	2007
Proved developed and undeveloped reserves			
Beginning of year	392,736	248,433	166,798
Purchases of reserves in place			
Discoveries and extensions	191,452	146,189	131,836
Revisions of previous estimates	(38,483)	21,661	(34,017)
Sales of reserves in place	(2,680)		(142)
Production	(29,978)	(23,547)	(16,042)
End of year	513,047	392,736	248,433
Proved developed reserves at beginning of year	216,229	122,598	73,912
Proved developed reserves at end of year	292,695	216,229	122,598
Proved undeveloped reserves at beginning of year	176,507	125,835	92,886
Proved undeveloped reserves at end of year	220,352	176,507	125,835

	Thousands of Barrels of Oil, Condensate and Natural Gas Liquids at December 31,		
	2009	2008	2007
Proved developed and undeveloped reserves -			
Beginning of year	18,308	16,531	7,195
Purchases of reserves in place			796
Discoveries and extensions	2,373	2,088	3,536
Revisions of previous estimates	(5,375)	36	5,245
Production	(503)	(347)	(241)
End of year	14,803	18,308	16,531
Proved developed reserves at beginning of year	7,869	6,536	1,638
Proved developed reserves at end of year	6,898	7,869	6,536
Proved undeveloped reserves at beginning of year	10,439	9,995	5,557

Proved undeveloped reserves at end of year	7,905	10,439	9,995

Following are the major causes of the Company s discoveries and extensions for natural gas:

2009	Drilling in the Barnett Shale play and additional proved undeveloped locations now permitted under new SEC guidelines
2008	Drilling in the Barnett Shale play
2007	Drilling in the Barnett Shale play

Following are the major causes of the Company s revisions of previous estimates for natural gas:

2009	Negative price revision in Barnett Shale and Gulf Coast
2008	Performance revision primarily in Barnett Shale
2007	Reclassification of natural gas liquids from natural gas to oil and condensate

In 2009, as a result of the adoption of new Commission rules regarding the reporting of oil and natural gas

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reserves, the Company removed 5.4 MMBls of oil reserves previously classified as proved in the Camp Hill Field that are not associated with wells that are expected to be both drilled prior to December 31, 2014 and into which the Company plans to inject steam prior to December 31, 2014. In 2007, the Company recorded significant oil discoveries and extensions due to drilling and development activity in the Barnett Shale region and additional formation evaluation in the Camp Hill field.

Standardized Measure

The standardized measure of discounted future net cash flows relating to the Company s ownership interests in proved oil and natural gas reserves as of year-end is shown below:

	Year Ended December 31,		
	2009	2008	2007
		(In thousands)	
Future gross reserves	$ 2,150,293	$ 2,501,460	$ 2,663,281
Future oil and natural gas operating expenses	(943,774)	(868,027)	(618,479)
Future development costs	(297,023)	(315,837)	(277,070)
Future income tax expenses	(73,656)	(223,828)	(394,569)
Future net cash flows	835,840	1,093,768	1,373,163
Less 10% annual discount for estimating timing of cash flows	(453,747)	(582,819)	(710,793)
Standard measure of discounted future net cash flows	$ 382,093	$ 510,949	$ 662,370

Effective for year-end 2009, SEC reporting rules require that year-end reserve calculations and future cash inflows 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 2009 under these new rules were $30.80 for oil, condensate and natural gas liquids and $3.30 per Mcf of for natural gas. For 2008 and 2007, future cash inflows were computed by applying year-end prices of oil and natural gas to year-end quantities of proved oil and natural gas reserves. Prices used in computing year-end 2008 and 2007 future cash inflows were $29.61, and $74.45 for oil, condensate and natural gas liquids, and $4.99 and $5.99 for natural gas, respectively. 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 natural 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 market value of the Company s oil and natural 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 reserve estimates.

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Change in Standardized Measure

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

	Year Ended December 31,		
	2009	2008	2007
Changes in Standardized Measure:			
Standardized measure beginning of year	$ 510,949	$ 662,370	$ 298,711
Revisions to reserves proved in prior years:			
Net changes in prices, net of production costs	(254,511)	(371,924)	142,126
Net changes in future development costs	108,831	(80,780)	43,812
Net changes due to revisions in quantity estimates	(71,840)	44,643	(7,614)
Accretion of discount	59,589	83,931	38,718
Changes in production rates (timing) and other	(70,616)	(67,218)	(39,793)
Total revisions	(228,547)	(391,348)	177,249
Discoveries and extensions, net of future production and development costs	76,419	228,037	340,503
Purchases of minerals in place			20,625
Sales of minerals in place	748		(351)
Sales of oil and gas produced, net of production costs	(80,997)	(171,944)	(101,127)
Previously estimated development costs incurred	34,816	91,832	15,918
Net change in income taxes	68,705	92,002	(89,158)
Net change in standardized measure of discounted future net cash flows	(128,856)	(151,421)	363,659
Standardized measure end of year	$ 382,093	$ 510,949	$ 662,370

13. SUPPLEMENTAL QUARTERLY FINANCIAL DATA (UNAUDITED)

The sum of the individual quarterly basic and diluted earnings (loss) per share amounts may not agree to year-to-date basic and diluted earnings (loss) per share amounts as a result of each period s computation being based on the weighted average number of common shares outstanding during the period.

2009	First	Second	Third	Fourth
	(In thousands, except per share amounts)			
Revenues	$ 31,203	$ 26,171	$ 23,847	$ 32,858
Costs and expenses, net	(156,748) [1]	(32,187)	(28,642)	(101,347) [1]
Net loss	$ (125,545)	$ (6,016)	$ (4,795)	$ (68,489)
Basic net loss per share	$ (4.07)	$ (0.19)	$ (0.15)	$ (2.20)
Diluted net loss per share	$ (4.07)	$ (0.19)	$ (0.15)	$ (2.20)

2008	First	Second	Third	Fourth
	(In thousands, except per share amounts)			
Revenues	$ 53,560	$ 67,388	$ 58,527	$ 37,202
Costs and expenses, net	(58,856)	(80,168) (2)	7,188 (2)	(129,888) (3)
Net income (loss)	$ (5,296)	$ (12,780)	$ 65,715	$ (92,686)
Basic net income (loss) per share	$ (0.18)	$ (0.42)	$ 2.15	$ (3.01)
Diluted net income (loss) per share	$ (0.18)	$ (0.42)	$ 2.12	$ (3.01)

(1) Includes a before tax $216.4 million and $122.5 million impairment of oil and gas properties for the first and fourth quarter, respectively.

(2) Includes a before tax $48.2 million loss and $77.7 million gain associated with derivatives for the second and third quarter, respectively.

(3) Includes a before tax $178.5 million impairment of oil and gas properties.

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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: March 16, 2010

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 S. P. Johnson IV	President, Chief Executive Officer and Director (Principal Executive Officer)	March 16, 2010
/s/ Paul F. Boling Paul F. Boling	Chief Financial Officer, Vice President, Secretary and Treasurer (Principal Financial Officer)	March 16, 2010
/s/ David L. Pitts David L. Pitts	Vice President and Chief Accounting Officer (Principal Accounting Officer)	March 16, 2010
/s/ Steven A. Webster Steven A. Webster	Chairman of the Board	March 16, 2010
/s/ Thomas L. Carter, Jr. Thomas L. Carter, Jr.	Director	March 16, 2010
/s/ Paul B. Loyd, Jr. Paul B. Loyd, Jr.	Director	March 16, 2010
/s/ F. Gardner Parker F. Gardner Parker	Director	March 16, 2010
/s/ Roger A. Ramsey Roger A. Ramsey	Director	March 16, 2010

/s/ Frank A. Wojtek	Director	March 16, 2010
Frank A. Wojtek		