CARRIZO OIL & GAS INC
Form 10-K
March 13, 2009

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, 2008

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 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 þ	Accelerated filer o	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, 2008, the aggregate market value of the registrant s Common Stock held by non-affiliates of the registrant was approximately $1,876.6 million based on the closing price of such stock on such date of $68.09.

At March 2, 2009, the number of shares outstanding of the registrant s Common Stock was 30,888,635.

DOCUMENTS INCORPORATED BY REFERENCE

Portions of the definitive proxy statement for the Registrant s 2009 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, 2008.

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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), 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, future exploration activity, production rates, financing for our 2009 exploration and development program, growth in production, development of new drilling programs, participation of our industry partners, funding for our Marcellus Shale operations, hedging of production and exploration and development expenditures, Camp Hill steam injection 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, may, pro
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 current economic downturn and credit crisis, 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, 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, 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.

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 are also actively seeking to establish a core area in another emerging resource play, the Marcellus Shale play in Pennsylvania, New York, West Virginia and Virginia. In addition to the Barnett and the Marcellus, we are active in other shale plays, including the Fayetteville in Arkansas, Barnett/Woodford in West Texas/New Mexico, Floyd/Neal in Mississippi, and the New Albany in Kentucky/Illinois. We also explore for, develop and produce natural gas and oil from traditional geologic trends along the onshore Gulf Coast area in Texas, Louisiana and Alabama, primarily in the Miocene, Wilcox, Frio and Vicksburg trends. Our other interests include properties in the U.K. North Sea.

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, 2008, we have participated in the drilling of 723 wells (356.1 net) with an apparent success rate of approximately 84%. 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 242 wells (173.6 net) in the Barnett Shale play. During 2008, we participated in 80 gross wells (62.8 net) wells in the Barnett Shale, including 66 wells that we operated. As of December 31, 2008, we had grown our proved reserves in the Barnett Shale to 432.1 Bcfe and our net average annual production in the Barnett Shale to 50.4 MMcf/d.

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 48%, while simultaneously maintaining a CAGR on our production of 28%. During 2008, we added a record 180.6 Bcfe to proved reserves, or a reserve replacement ratio of 705%. 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 25.6 Bcfe, a 47% increase from 2007, including 22.4 Bcfe from wells that we drilled and operated. At year-end 2008, our proved reserves were approximately 78% natural gas and approximately 22% crude oil.

Our Board of Directors has approved an initial capital and exploration budget of $105.0 million for 2009. This budget 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, $224.9 million and $187.3 million in 2008, 2007 and 2006, respectively. We currently expect to spend the majority of our capital and exploration budget for 2009 on drilling in our Barnett Shale core area. Where possible in order to maximize our liquidity, while increasing profitability of our projects, we currently intend to defer certain fracing, completion and pipeline costs because we currently expect that the costs of these services will decline significantly over the remainder of 2009. We intend to finance our 2009 capital and exploration budget primarily from cash flow from operations. Other available sources of funding include our senior credit facility and proceeds from the possible selective sale of non-core assets.

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 2008, we had interests in 189 gross (135.0 net) producing wells and 53 gross (38.6 net) non-producing wells that were drilled and waiting on completion and/or pipeline connection in the Barnett Shale. We operate 115 of the gross producing wells in the Barnett Shale that we have interests in and 43 of the gross wells we have drilled but are not yet producing there . During that same period, we increased our acreage holding in the Barnett Shale area to 82,331 gross (59,336 net) mineral acres. In addition we control an additional 864 gross and net mineral acres under lease options.

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During 2008, we drilled 80 additional gross wells (62.8 net) of which we operated 66. Net proved reserves grew by 57% from 276.0 Bcfe on December 31, 2007 to 432.1 Bcfe on December 31, 2008. We currently expect to invest approximately $85 million (representing over 80% of our total 2009 capital and exploration expenditures) to drill an additional 45 gross (30.0 net) wells in this area in 2009. In addition, we plan to frac, complete and bring on production approximately 23 gross (20.7 net) wells during 2009, thereby gradually increasing our significant inventory of drilled, but not yet frac d and completed wells.

Marcellus Shale Area

In late 2007, we established a new core area in the Marcellus Shale play, primarily in upstate New York, Pennsylvania, West Virginia and 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.

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 Footnote to Consolidated Financial Statement Footnote 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. Because we initially committed acreage with a substantially higher market value to the joint venture than Avista, Avista agreed to fund the first approximately $71.5 million of joint venture expenditures related to the Marcellus Shale play. We currently expect Avista to fund all of the joint venture s 2009 capital and exploration obligations, as well as the general and administrative expenses of our employees working on this play during the period. After these initial capital obligations have been met, we and Avista will each share all costs of joint venture operations in accordance with our participating interests, which we expect will generally be 50/50.

As of year-end 2008, we and Avista had dedicated to the joint venture interests in approximately 230,146 gross (183,315 net) acres in the Marcellus Shale, principally in Pennsylvania, West Virginia and New York. In 2008, we participated in our first two vertical wells in the Marcellus Shale, including one in Pennsylvania and the other well in New York, where we also acquired our first 2-D seismic. We currently expect to participate in 12 gross (4.0 net) Marcellus Shale play area wells in 2009, including eleven vertical wells and one horizontal well, all of which we currently expect will be funded by Avista under our joint venture agreement. 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.

Onshore Gulf Coast Area

In 2008, we drilled six gross (3.3 net) wells, all but one of which were apparent successes, and three of which we operated. During 2009, we currently have budgeted to participate in drilling three gross (1.0 net) wells and also expect to conduct an active workover and intervention program to maintain production while reducing capital expenditures. We currently plan to spend approximately $3.0 million for capital expenditures in the onshore Gulf Coast area during 2009.

U.K. North Sea Area

We currently hold interests in three licenses in the U.K. North Sea (two in the Central Graben area and one in the Southern Gas Basin). The two licenses in the Central Graben area cover substantially the entire Huntington discovery. On these three licenses, we promoted our interests to other parties more experienced in drilling and operating in this region, leaving us with a carried interest on four exploration wells. Two of the four drilled wells resulted in three discoveries, including two discoveries in the Huntington Field and an apparent gas discovery at our Monterey prospect in the Southern Gas Basin. From inception of our activity in this area in early 2003 through year-end 2006, we have incurred only $1.7 million in total project costs (net of partner reimbursements) in an effort to create value while minimizing front-end cost. In 2008 and 2007, we spent $5.5 million and $9.4 million, respectively, largely for our share in the appraisal drilling and front-end development planning, engineering and studies related to the development of the portion of the Huntington discovery consisting of the Paleocene Forties formation, and to a lesser extent, appraisal drilling on that portion of the Huntington discovery consisting of the Jurassic Fulmar formation. We have currently budgeted $3.0 million to continue work in the Huntington Field in 2009, primarily for predevelopment project costs.

Other Areas

We have currently budgeted $2.0 million for capital and exploration expenditures in 2009 for all of our other shale plays, including the Fayetteville, Floyd, New Albany and Barnett/Woodford, as well as for our other non-Gulf Coast traditional oil and gas plays, including our Camp Hill Field. Due to current economic conditions, we currently plan to participate in wells where our interest is carried by other partners, wells that we believe have a high probability of success and wells in which we are obligated to participate to maintain our acreage. We will also focus on workover, well intervention and lease maintenance to maintain existing production. We currently expect that lease acquisition will be limited to maintaining and consolidating existing lease positions in these areas.

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

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 reduced demand for natural gas and lower natural gas prices as a result of the current economic downturn and the current cost of accessing the capital markets, we have reduced our capital and exploration budget for 2009 to $105 million, and we are striving to maintain our financial flexibility and a positive production growth profile. Any further deterioration in commodity prices may cause us to reduce our capital and exploration budget for 2009 even further.

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 six years and our 100% drilling success rate in the Barnett Shale area since inception in 2003. During 2009, we plan to drill approximately 45 gross (30.0 net) wells in the Barnett Shale area, and three gross (1.0 net) wells in the onshore Gulf Coast area. We also expect to complete 44 gross (44.0 net) wells in our Camp Hill Field. We have planned approximately $105.0 million for capital expenditures in 2009, approximately $90.0 million of which we expect to use for drilling activities, including $85.0 million in the Barnett Shale area and $3.0 million in the onshore Gulf Coast area. In addition, we currently expect to participate in 12 gross (4.0 net) Marcellus Shale play area wells in 2009, including eleven vertical wells and one horizontal well, all of which we currently expect will be funded by Avista under our joint venture agreement with them.

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 150 horizontal wells. We are attempting to leverage this advantage in other shale trends, principally in the Marcellus Shale, by utilizing the knowledge and expertise of our personnel and partnering with Avista, a joint venture partner that has significant financial knowledge, expertise and capital. 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 230,000 acres and where we currently expect Avista to fund substantially all of the joint venture s 2009 capital and exploration program. We also intend to continue to explore in the onshore Gulf Coast area, where members of our staff have been exploring for over 30 years.

Maintain a Conservative Exploration and Development Portfolio. Recently 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.

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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 additional technical input and economic review from knowledgeable industry participants regarding our prospects. 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. We also seek to operate our core projects in order to better control drilling costs and the timing of drilling. Our joint venture with Avista in the Marcellus Shale is a recent and prominent example of this strategy.

Retain and Incentivize a Highly Qualified Technical Staff. We employ over 36 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 fracturing 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 have chosen to reduce the number of rigs we operate in the Barnett Shale trend, while maintaining our highly experienced staff. To accomplish this, we seek to reduce costs by drilling more wells on units where we hold a lower working interest than our historic average. We are also seeking 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 deferring certain fracing, completion and pipeline hookup costs during periods of low natural gas prices and while our cost for these services continues to decline.

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 fracturing 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, or our joint venture partners. 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.

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.

In our onshore Gulf Coast area, we generally seek to develop prospects consistent with our expertise and based upon our analysis of 3-D seismic data. We currently own the rights to over 8,527 square miles of seismic data in our Gulf Coast area, together with the right to an additional 350 square miles as a result of a data swap with a leading seismic multi-client library provider. After developing a prospect and obtaining the leasehold rights on the acreage where the prospect is located, we generally seek to farm-out a portion of our interest in the prospect and associated leasehold acreage on a promoted basis to reduce our risks and to control our costs.

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, 2008, we operated 218 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 fracturing. During 2008, we operated 66 of the 80 gross wells that we participated in drilling in the Barnett Shale.

We emphasize preplanning in project development to lower capital and operational costs and to efficiently integrate potential well locations into the existing and planned infrastructure, including gathering systems and other surface facilities. In constructing surface facilities, we seek to use reliable, high quality, used equipment in place of new equipment to achieve cost savings.

SIGNIFICANT PROJECT AREAS

Our operations are focused primarily in the Barnett Shale trend in North Texas, 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 West Texas, New Mexico, Mississippi, Kentucky, Illinois, Arkansas, and North Dakota 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	2008	2009 Plan
					(In millions)	
Barnett Shale	189	135.0	524	59,336	$ 227.6	$ 85.0
Marcellus Shale[1]	1	0.2		91,659	1.3	
Gulf Coast	113	31.4	8,527	40,009	19.9	3.0
U.K. North Sea			2,057	24,798	4.2	
Other Shales	14	0.4	18	263,394	1.2	
Camp Hill	57	55.8		928	7.1	2.0
Other			2,130	45,226	3.3	
Total	374	222.8	13,256	525,350	$ 264.6	$ 90.0

(1) We expect our capital and exploration expenditures during 2009 in the Marcellus, including a joint venture drilling

budget of $12.7 million, will be funded by our joint venture partner until they match our initial contribution (see Marcellus Shale Area below).

Barnett Shale Area

As of December 31, 2008, we had approximately 82,331 gross and 59,336 net mineral acres under lease and 864 gross and net mineral acres subject to lease options in the Barnett Shale. Nearly 37% of our total Barnett Shale lease acreage, 30,871 gross acres, is either in currently designated producing units, units on which wells have been drilled and are awaiting completion and/or hookup, or will be placed in units that we currently plan to drill in 2009. As of December 31, 2008, we had drilled 53 gross (38.6 net) Barnett Shale wells that were waiting on completion and/or pipeline hook-up, of which we operated 43. Between January 1, 2009 and February 20, 2009, we placed an additional 15 gross (10.3 net) wells on production, while drilling another ten gross (9.5 net) wells, leaving us with an inventory of 47 gross (36.9 net) wells drilled and waiting on completion and/or pipeline hook-up. Eight gross (6.6 net) wells had been frac d and completed and were waiting on imminent pipeline connection.

During 2009, we intend to pursue a deliberate strategy of developing an inventory of drilled wells that are waiting on fracing and completion. We are undertaking this strategy due to the recent precipitous decline in natural gas prices, and our expectation that fracing and completion costs will drop significantly over the remainder of the year.

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 12,500 feet including the lateral section. Typical costs to drill and complete a Barnett Shale horizontal well ranged from approximately $2.0 million to $4.2 million during 2008. However, we currently expect the cost of fracing and completion to decline in 2009 due to reduced fracing and completion activity as a result of lower natural gas prices. 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 are now observing an extended production test of this technology on one of our well sites. If this strategy ultimately proves successful, we expect it will permit us to more efficiently develop and produce thicker sections of the Barnett Shale and may permit 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.

We continue to focus our 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 plan to drill our second set of six to eight wells from this well pad during 2009, with the potential of drilling up to 16 more wells in the future. As of year-end 2008, we were operating four rigs that were drilling exclusively horizontal wells in the Barnett Shale. However, in connection with our reduced capital budget, we have released one of these rigs in early March.

Marcellus Shale Area

As of December 31, 2008, we owned interests in 230,148 gross (91,659 net) acres in the Marcellus shale trend, principally in Pennsylvania, New York and West Virginia. Our principal joint venture partner in this trend is Avista. We serve as operator of our joint venture with Avista under a joint operating agreement with Avista and provide all geotechnical, 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 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 we default under the terms of any pledge of our 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 last August, 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). After the Initial Cash Contribution has been funded by Avista, the parties will share all costs of joint venture operations in accordance with their participating interests, which we expect will generally be 50/50. As a result of Avista s obligation to fund the Initial Cash Contribution, we do not currently expect that we will be required to contribute any cash to fund capital and exploration expenses in the Marcellus Shale during 2009.

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 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.

Gulf Coast Area

In recent years, we have drilled wells in the Wilcox, Smackover and Frio/Vicksburg trends where our exploration team has many years of experience. Our Gulf Coast area generally contains geologically complex natural gas objectives well-suited for drilling using 3-D seismic evaluation. We have developed a large inventory of undrilled prospects in the Gulf Coast area, almost all of which are supported by 3-D seismic. We have data licenses for approximately 8,527 square miles of 3-D seismic data and control 40,009 net acres of leasehold in the Gulf Coast area. In 2008, we incurred capital drilling expenditures of $19.9 million and drilled six gross (3.3 net) wells, three of which we operated. We currently have budgeted to drill three gross (1.0 net) wells during 2009 and also expect to conduct an active workover program to maintain production while reducing capital expenditures. These activities are budgeted to cost approximately $3.0 million in 2009. From January 1, 2003 through December 31, 2008, we drilled and completed 101 wells (31.2 net) in the Gulf Coast area on 119 attempts.

U.K. North Sea Region

We believe our low entry cost U.K. North Sea strategy is a natural extension of our previous experience exploiting hydrocarbons in proven mature regions where significant additional exploration potential exists, through available, large modern 3-D seismic surveys, related technology and proper risk management. We currently hold interests in three licenses (two in the Central Graben area and one in the Southern Gas area) totaling approximately 24,800 net acres and currently expect to be granted interests in four new licenses totaling another 164,518 gross (115,548 net) acres in the 25th licensing round of the U.K. government. The two existing licenses in the Central Graben area cover substantially the entire Huntington discovery.

Our Huntington discovery well (in which we retained a 15% working interest) was drilled in the second quarter of 2007 in water depths of approximately 300 feet. This exploration well resulted in two independent discoveries, one in the shallower Paleocene Forties reservoir and another in the deeper Upper Jurassic Fulmar objective. A combined maximum test rate of over 11,000 Bbls/d equivalent was measured in the discovery well.

The Huntington Forties reservoir was largely appraised by year-end 2007 with eight high-angle deviated side-tracks (laterals) drilled radially from a central top hole location at a net cost to us of approximately $9.2 million. We and our joint venture partners have been reviewing these well results and have commenced preliminary field development planning for the Forties reservoir, including the refurbishment and manufacture of certain long-lead items such as subsea wellheads. In 2008, we incurred approximately $2.6 million in connection with this pre-development work.

In late 2008, two wells were drilled by the joint venture in the adjoining block 22/14a, one of which confirmed the extension of a small portion of the Huntington field on their license. This outcome will now require us and our joint venture partners to enter into negotiations with the block 22/14a joint venture to prepare a joint development plan for the field to be submitted for approval to the U.K. government in order to unitize the field. The parties have begun preliminary unitization discussions.

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In January 2009, Oilexco North Sea Limited (Oilexco), our largest joint venture partner with respect to the Huntington Field, and at that time the operator of our license, entered into insolvency proceedings in the U.K. We have not suffered a direct material adverse financial impact as a result of Oilexco s bankruptcy. However, this action resulted in the removal of Oilexco as operator and the subsequent appointment of a subsidiary of E.ON Ruhrgas AG as license operator. We believe that these events have caused some delay in field development planning and unitization discussions. As a consequence, although our joint venture remains committed to timely development of the Huntington Field, we currently believe that production from this field will not commence until at least the end of 2010 or the first half of 2011. The administrators of Oilexco s insolvency proceeding have announced that they are actively seeking to sell all of Oilexco s business and assets, including its interest in the Huntington Field. We are also considering 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.

Following the initial Huntington discovery well, we and our joint venture partners completed an appraisal well in the Huntington Fulmar discovery in early 2008. At least one additional Fulmar appraisal well will likely be necessary prior to the sanctioning of the development of the Fulmar reservoir. We and our joint venture partners have not yet agreed upon the timing for this next well, but it is currently expected to be in early 2010.

The U.K. government has informed us that we were the successful bidder, along with certain joint venture partners, on four additional licenses in the 25th licensing round conducted in mid 2008. License winners have been announced but no licenses have been formally awarded. Our interests in these blocks vary from 40% to 100%. None of these blocks, if granted, contain firm well commitments, nor would they require us to incur material capital expenditures in the near term.

Other Shale Project Areas

We continue to evaluate our acreage and seismic and well data in other resource shale projects. Regional mapping of shale extent, depth, thickness, organic content, thermal maturation, mineralogy, as well as cost and availability of acquiring leases, are analyzed to define the project fairways to lease, and to assist in identifying the locations for initial exploratory wells. We have been successful in acquiring approximately 34,400 gross (26,300 net) acres in the Fayetteville Shale in Arkansas, and approximately 76,000 gross (63,000 net) acres in the Woodford/Barnett Shale in West Texas and New Mexico comprised of over 58,000 net acres in the Marfa Basin and 5,323 net acres in the Delaware Basin. We have leased approximately 30,000 net acres in the New Albany shale project located in Illinois and Kentucky. In 2008, we invested $1.2 million dollars to drill nine gross (0.3 net) wells in the Fayetteville Shale. In 2009, we currently plan to further evaluate this acreage position and data in our possession and to participate only in wells that are operated by third parties, particularly in the Fayetteville Shale, where a number of industry partners are active.

Camp Hill Field

We own interests in approximately 2,630 gross acres in the Camp Hill Field in Anderson County, Texas. We have an average working interest of approximately 92.1% in this field and an average net revenue interest of 71.0%. We currently operate all of these leases. During 2008, we drilled 17 gross (17.0 net) producing wells and 13 gross (13.0 net) injection wells in the field. Our capital and exploration expenditures during 2008 in the Camp Hill Field were $10.4 million. During the year ended December 31, 2008, the project produced an average of 33 Bbls/d of 19 API gravity oil, but was up to 72 barrels of oil per day in December. As a result of our aggressive drilling program in 2008, we converted over 1.4 million Bbls from proved undeveloped to proved developed reserves. During 2009, we currently plan to seek to negotiate lower gas prices (which is used to generate steam in the field) in an attempt to improve field economics, work on upgrades to the field infrastructure, including converting a deep well drilled in 2008 to a water disposal well, perforating and completing 44 of the wells drilled during 2008 and in prior years, hooking the new injectors up to the steam generators and refurbishing two steam generators, and observing the field response to the additional 30 wells drilled in the field during 2008. We do not currently plan to drill any wells in this field in 2009.

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, 2008 averaged $84.69 per barrel ($14.11 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 West Texas Intermediate crude (an average premium of $0.15 per Bbl to Flint Hills WTI during the year ended December 31, 2008) due to its suitability as a lube oil feedstock.

As of December 31, 2008, we had 8.2 MMBbls of proved oil reserves in this project, with 3.2 MMBbls of oil reserves currently developed. These proved reserves are based on an ultimate recovery factor of 49%. The proved undeveloped reserves at the Camp Hill Field constitute 6% of our proved reserves and account for 4% of our present value of net future revenues from proved reserves as of December 31, 2008.

Prior to 2003, we estimated an ultimate recovery efficiency (i.e. the percentage of the oil in the ground that we would be able to produce economically) after steam drive of 45% of the original oil in place in the Camp Hill Field. As of January 1, 2003, we raised our estimate to an ultimate recovery of 55% of the estimated original oil in place based upon our review of recovery efficiencies from prior projects by other companies in both the Camp Hill Field as well as in nearby projects that we considered to have similar geologic and hydrocarbon attributes. We lowered our estimated recovery efficiency as of December 31, 2005 to 49% of the estimated original oil in place in the field. We believe this revised 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, 2008 and is currently still producing.

Although we have increased our development activities in the Camp Hill Field since 2005, this follows an extended period during which we deferred development in the field. We deferred development (1) to optimize returns by awaiting an economic entry point for developing a cogeneration plant as further explained below, (2) to pursue other opportunities in both our onshore Gulf Coast area and later, the Barnett Shale and other shale plays with higher rates of return and (3) to continue increasing our net acreage position in the field in a competitive environment. Although we at all times believed that we could develop this field on a profitable basis, we nonetheless believed that we were optimizing our economic position by deferring development. We acquired our initial interests in the Camp Hill Field in 1993. After the acquisition, we injected steam for much of the period from 1994 to 2000. Since ramping up activity commencing with seven wells in 2005, we have drilled ten wells (including six injection wells) in 2006, 30 wells (including 13 injection wells) in 2007 and 30 wells (including 13 injection wells) in 2008.

To fully develop the field, we expect to drill an additional approximately 244 gross wells (including 111 injection wells) from 2009 through 2024, at a total estimated cost of approximately $22.7 million and total operating costs, including steam, of approximately $127.2 million. The precise timing and amount of our expenditures on additional well drilling and increased steam injection to develop the proved undeveloped reserves in this project will depend on several factors including the relative prices of oil and natural gas.

The most important reason for our deferral of full development prior to the end of 2005 was the potential for significantly improved profitability that would result from the construction of a nearby cogeneration plant. Cogeneration plants typically provide steam at less than half the cost of small steam generators. Steam costs are critical to the economics of the development of the field. Expected steam costs far outweigh the capital costs for the development of the Camp Hill Field. We currently estimate approximately $114 million in steam costs compared to $22.7 million for drilling and development capital that is needed to fully develop the proved undeveloped reserves in this field.

We have had difficulties maintaining desired levels of steam injection in the field over the last several years. Originally, the steam generators we expected to use were not available due to delays in repairs and permitting issues. We injected steam in the Camp Hill Field through one of our generators until it encountered operational damage in January 2007. We acquired a replacement generator in 2008, and this generator commenced steam injection shortly thereafter. Our other two generators were not available for injection in 2007 and 2008 due to unexpected permitting issues and the need for repair work. We received the permits for these two generators to recommence injection in the fourth quarter of 2007. Although these permits only allow us to inject steam at 80% of the rate that we had anticipated, based upon the rate under the prior permits for these same generators, we expect to continue to appeal to the regulatory authorities to reinstate the 100% rate of generation allowed under the original permits. The impact of a lower generation rate assumption (incorporated into our December 31, 2008 proved reserves) does not reduce our proved reserves from prior estimates. However, it does 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. Prospectively, we expect to continue to use the lower generation rate assumption in our proved reserve estimates, unless and until such time that we are successful in increasing the generation rates in our permits. We currently expect that one of these generators will be ready to inject steam by the end of 2009 and the other should be operational in 2010. In addition, we obtained a small portable generator in 2008. This small generator is now also undergoing repairs.

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 that are currently part of our capital budget 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 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.

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, 2008. The reserve data and the present value as of December 31, 2008 were prepared by Ryder Scott Company, LaRoche Petroleum Consultants, Ltd. and Fairchild & Wells, Inc., Independent Petroleum Engineers. For further information concerning these independent engineers estimates of our proved reserves at December 31, 2008, see the reserve reports included as exhibits to this Annual Report on Form 10-K. The PV-10 value was prepared using constant prices 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.

		Proved Reserves	
	Developed	**Undeveloped**	**Total**
		(Dollars in thousands)	
Oil and condensate (MBbls)	7,869	10,439	18,308
Natural gas (MMcf)	216,229	176,507	392,736
Total proved reserves (MMcfe)	263,443	239,141	502,584
PV-10 Value[(1)(2)]	$466,268	$129,623	$595,891

(1) The PV-10 value as of December 31, 2008 is pre-tax and was determined by using the December 31, 2008 sales prices, which averaged $40.12 per Bbl of oil,

$19.62 per Bbl of natural gas liquids and $4.99 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 (2) 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.

(2) Future income taxes and present value discounted (10%) future income taxes were $407.9 and $154.6 million, respectively. Accordingly, the after-tax PV-10 value of Total Proved Reserves (or Standardized Measure of Discounted Future Net Cash Flows) is $441.3 million.

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, Ryder Scott Company Petroleum Engineers, Fairchild & Wells, Inc. and LaRoche Petroleum Consultants, Ltd. each used year-end oil and natural gas prices in effect at December 31, 2008, 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, 2008. 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 432.1 Bcfe, or 86% of our proved reserves, for the year ended December 31, 2008, which reserves were located on our Barnett Shale properties. Fairchild & Wells, Inc. determined 49.2 Bcfe, or 10% of our proved reserves, for the year ended December 31, 2008, which reserves were located on our properties in the Camp Hill Field. Ryder Scott Company Petroleum Engineers determined 21.3 Bcfe, or 4% of our proved reserves, for the year ended December 31, 2008, which reserves were located on our Gulf Coast and all other remaining properties

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 41.8% in 2008, from 38.2% in 2007, and from 25.0% in 2006. Set forth below is our reserve replacement ratio for the years ended December 31, 2008, 2007 and 2006.

	2008	**2007**	**2006**
Reserve Replacement Ratio	705%	887%	607%

Volumes, Prices and Oil & Natural Gas Operating 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,		
	2008	2007	2006
Production volumes			
Oil (MBbls)	186	241	255
Natural gas (MMcf)	24,513	16,042	10,176
Natural gas equivalent (MMcfe)	25,632	17,487	11,705
Average sales prices			
Oil (per Bbl)	$ 99.74	$ 71.42	$ 63.62
Natural gas (per Mcf)	7.80	6.77	6.56
Natural gas equivalent (per Mcfe)	8.19	7.19	7.09
Average costs (per Mcfe)			
Camp Hill operating expenses	$ 14.11	$ 16.12	$ 11.50
Other operating expenses	1.44	1.36	1.33
Total operating expenses(1)	1.48	1.41	1.40

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

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 $14.4 million, $11.7 million and $10.0 million for the years ended December 31, 2008, 2007 and 2006, respectively. We have also included capitalized overhead in our finding cost of $7.8 million, $4.5 million and $3.5 million for the years ended December 31, 2008, 2007 and 2006, respectively. We have also included non-cash asset retirement obligations of $0.6 million, $2.0 million and $0.3 million for the years ended December 31, 2008, 2007 and 2006, respectively.

	Year Ended December 31,		
	2008	2007	2006
		(In thousands)	

Acquisition costs:			
Other unproved properties	$ 271,618	$ 54,467	$ 48,409
Proved properties			
Exploration	235,382	144,402	104,473
Development	49,626	30,562	37,889
Asset retirement obligation	630	1,961	299
Total costs incurred	$ 557,256	$ 231,392	$ 191,070
Total proved reserves added (MMcfe)	180,594	155,139	71,066
Average all-sources finding cost (per Mcfe)	$ 3.09	$ 1.49	$ 2.69
Average all-sources finding cost (per Mcfe) excluding Marcellus[1]	$ 2.75	$ 1.49	$ 2.69
Average finding and development cost (per Mcfe)[2]	$ 1.68	$ 1.22	$ 2.10
Average drilling finding cost (per Mcfe)	$ 1.58	$ 1.14	$ 2.01

(1) The all source finding cost (per Mcfe), excluding our Marcellus Shale area activities (which began in 2008 and has been primarily limited to land acquisitions).

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

For the three year period ended December 31, 2008, our total adjusted cost for exploration, development and acquisition activities was approximately $979.8 million. Total exploration, development and acquisition activities for the three year period ended December 31, 2008 have added approximately 406.8 Bcfe of net proved reserves at an all-sources finding cost of $2.41 per Mcfe.

Our finding and development cost computation excludes net additions/reductions to total future development costs with respect to proved undeveloped properties necessary to convert those properties into proved developed properties of $47.6 million, $75.7 million and $31.4 million at December 31, 2008, 2007 and 2006, respectively, and includes total additions to proved undeveloped reserves of 53.3 Bcfe, 59.6 Bcfe and 28.4 Bcfe for the years ended December 31, 2008, 2007 and 2006, respectively. Accordingly, had we included future development costs in our computations, the average all-sources finding costs would have been $3.35, $1.98 and $3.13 per Mcfe for the years ended December 31, 2008, 2007 and 2006, respectively.

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.

Development, Exploration and Acquisition Capital Expenditures

The following table sets forth certain information regarding the gross costs incurred in the purchase of proved and unproved properties and in development and exploration activities.

	Year Ended December 31,		
	2008	**2007**	**2006**
		(In thousands)	
Acquisition costs			
Unproved prospects	$ 271,618	$ 54,467	$ 48,409
Proved properties			
Exploration	235,382	144,402	104,473
Development	49,626	30,562	37,889
Asset retirement obligation	630	1,961	299
Total costs incurred[1]	$ 557,256	$ 231,392	$ 191,070

(1) Excludes capitalized interest on unproved properties of $14.4 million, $11.7 million and $10.0 million for the years

ended December 31, 2008, 2007 and 2006, respectively, and includes capitalized overhead of $7.8 million, $4.5 million, and $3.5 million for the years ended December 31, 2008, 2007 and 2006, respectively. The table also includes non-cash asset retirement obligations of $0.6 million, $2.0 million and $0.3 million, respectively, for the years ended December 31, 2008, 2007 and 2006.

Drilling Activity

The following table sets forth our drilling activity for the years ended December 31, 2008, 2007 and 2006. 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,					
	2008		2007		2006	
	Gross	Net	Gross	Net	Gross	Net
Exploratory Wells						
Productive	83	60.0	65	42.8	47	26.9
Nonproductive	2	0.3	1	0.4	3	0.9
Total	85	60.3	66	43.2	50	27.8
Development Wells						
Productive	31	24.2	29	24.0	20	17.1
Nonproductive	3	3.0	1	1.0		
Total	34	27.2	30	25.0	20	17.1

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

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, 2008.

	Company Operated		Other		Total	
	Gross	Net	Gross	Net	Gross	Net
Oil	67.0	59.3	2.0	1.2	69.0	60.5
Natural gas	151.0	122.3	154.0	40.0	305.0	162.3
Total	218.0	181.6	156.0	41.2	374.0	222.8

Acreage Data

The following table sets forth certain information regarding our developed and undeveloped lease acreage as of December 31, 2008. 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.

	Developed Acreage		Undeveloped Acreage		Total	
	Gross	Net	Gross	Net	Gross	Net
Barnett Shale Texas	30,871	20,144	51,460	39,192	82,331	59,336
Marcellus Shale						
New York			34,642	8,213	34,642	8,213
Pennsylvania			83,862	31,393	83,862	31,393
West Virginia			98,405	45,522	98,405	45,522
Virginia and other			13,239	6,531	13,239	6,531
Marcellus Shale Total			230,148	91,659	230,148	91,659
Gulf Coast						
Texas	30,853	9,616	34,906	13,514	65,759	23,130
Louisiana	1,977	1,024	15,625	14,571	17,602	15,595
Alabama	160	42	1,800	1,242	1,960	1,284
Gulf Coast Total	32,990	10,682	52,331	29,327	85,321	40,009
U.K. North Sea(1)			110,628	24,798	110,628	24,798
Other Shales(2)	293	54	438,977	263,340	439,270	263,394
Other Texas(3)	2,259	2,042	52,987	42,969	55,246	45,011
Other			7,618	1,143	7,618	1,143
Total	66,413	32,922	944,149	492,428	1,010,562	525,350

(1) U.K. North Sea does not include the four licenses that we have been notionally awarded in the 25th bid round that were announced last year. These four licenses include 164,518 gross (115,548 net) acres of additional undeveloped acreage.

(2) Other Shales principally includes the Fayetteville Shale in Arkansas; the New Albany Shale

in Kentucky and Illinois; the Floyd Shale in Mississippi; the West Texas Barnett/Woodford in Texas and New Mexico; and the Bakken in North Dakota.

(3) Other Texas includes the Camp Hill Field and other plays in North, East and Central Texas.

The table does not include 16,735 gross and 6,200 net acres under lease option that we had a right to acquire in Texas pursuant to various seismic and lease option agreements at December 31, 2008. 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 7% of our acreage will expire in 2009, 24% will expire in 2010 and 42% will expire in 2011.

Marketing

Our production is marketed to third parties consistent with industry practices. Typically, oil is sold at the wellhead at field-posted prices plus a bonus and natural gas is sold under contract at a negotiated price based upon factors normally considered in the industry, such as distance from the well to the pipeline, well pressure, estimated reserves, quality of natural gas and prevailing supply and demand conditions.

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. We take an active role in determining the available pipeline alternatives for each property based on historical pricing, capacity, pressure, market relationships, seasonal variances and long-term viability.

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

We from time to time market our own production where feasible with a combination of market-sensitive pricing and forward-fixed pricing. We utilize forward pricing to take advantage of anomalies in the futures market and to hedge a portion of our production deliverability at prices exceeding forecast. 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 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.

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 may now be 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 natural gas and oil 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. However, we do not believe our operations will be materially adversely affected by any such requirements.

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.

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 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 greenhouse gases, 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, as a result of the U.S. Supreme Court s decision in April 2007 in *Massachusetts v. Environmental Protection Agency*, the EPA may regulate carbon dioxide and other greenhouse gas emissions from mobile sources such as cars and trucks, even if Congress does not adopt new legislation specifically addressing emissions of greenhouse gases. The Court s holding in *Massachusetts* that greenhouse gases including carbon dioxide fall under the federal Clean Air Act s definition of air pollutant may also result in future regulation of carbon dioxide and other greenhouse gas emissions from stationary sources under certain Clean Air Act programs. New federal or state restrictions on emissions of carbon dioxide that may be imposed in areas of the United States in which we conduct business could also adversely affect our cost of doing business and demand for the oil and gas we produce.

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.

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Title to Properties; Acquisition Risks

We believe we have satisfactory title to all of our producing properties in accordance with standards generally accepted in the natural gas and oil industry. Our properties are subject to customary royalty interests, liens incident to operating agreements, liens for current taxes and other burdens which we believe do not materially interfere with the use of or affect the value of 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 before 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,		
	2008	**2007**	**2006**
DTE Energy Trading, Inc.	39%		
Cokinos Natural Gas Company	11%	11%	
Reichmann Petroleum			10%
Chevron/Texaco			11%
Houston Pipeline Company		11%	
Energy Transfer		10%	
Crosstex Energy	10%	15%	

Because alternate 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, 2008, we had 104 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 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 in our Corporate Governance section of our website at www.crzo.net.

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 continued credit crisis and related turmoil 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 improve. 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 crisis 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 mid 2008, publicly quoted spot natural gas and oil prices have declined significantly from record levels in July 2008 of approximately $145.31 per Bbl (West Texas Intermediate) and $11.87 per Mcfe (WAHA) to approximately $40.07 per Bbl and $2.92 per Mcfe as of March 2, 2009. In the past, some oil and gas companies have curtailed production to mitigate the impact of low natural gas and oil prices. We may determine to shut in a portion of our production as a result of the decrease in prices. The decrease in natural gas and oil prices has had a significant impact on our financial condition, planned capital expenditures and results of operations. Further declines 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 budget 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 Form 10-K represents 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. Changes in interpretations as to classification standards or disagreements with our interpretations could cause us to write down these reserves.

As of December 31, 2008, approximately 58.6% 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, 2008 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 certainty with respect to development plans for proved undeveloped reserves could cause the discontinuation of the classification of these reserves as proved. Although, since 2005, we have increased our development of the Camp Hill Field in East Texas, we have in the past chosen to delay development of our proved undeveloped reserves in the Camp Hill Field in favor of pursuing shorter-term exploration projects with higher potential rates of return, adding to our lease position in this field and further evaluating additional economic enhancements for this field s development.

The discounted future net cash flows included in this 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 based on prices and costs 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 may own less than 100% of the working interest in certain leases acquired by us, 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 decline 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. Many of our project partners are experiencing 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, an example of which recently occurred in our Huntington Field, 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 current credit crisis 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. 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 that began in mid 2008, 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 and Carrizo Marcellus Holding Inc. 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 and the ratio of EBITDA to debt coverage. 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 budget, sell non-strategic assets, opportunistically modify or increase our natural gas hedges, or approach our lenders under our senior credit facility for modification 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 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. In the event the amount outstanding 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 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 February 15, 2009, we have participated in the drilling of only two wells in the Marcellus Shale area. Other operators in the Marcellus Shale area also have limited experience drilling in the area. 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.

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 governmental regulations and environmental risks.

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.

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;
- 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 interrupt 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 substantial 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.

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.

The marketability of our production depends in part upon the availability, proximity and capacity of natural gas gathering systems, pipelines and processing facilities. 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 recently begun entering into firm transportation agreements in the Barnett Shale, which are more costly to us than the interruptible or short-term transportation agreements. Our ability to produce and market natural gas on a commercial basis could be harmed by any significant change in the cost or availability of such markets, systems or pipelines.

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 in 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. Once incurred, a write-down of natural gas and oil properties is not reversible at a later date. We recorded a ceiling test limitation write-down at the end of 2008, and we could incur additional write-downs in the future, particularly as a result of a continuation in the decline of natural gas and oil prices. See Item 7. Management s Discussion and Analysis of Financial Condition and Results of Operations Summary of Critical Accounting Policies for additional information on these matters.

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 installation of permanent equipment for the production of oil or natural gas or, in the case of a dry hole, the reporting of abandonment to the appropriate agency.

Developed acreage. The number of acres which are allocated or assignable to producing wells or wells capable of production.

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

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

Exploratory well. A well drilled to find and produce oil or natural gas reserves not classified as proved, to find a new reservoir in a field previously found to be productive of oil or natural gas in another reservoir or to extend a known 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.

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.

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 in effect as of the date indicated, 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%.

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

Proved developed nonproducing reserves. Proved developed reserves expected to be recovered from zones behind casing in existing wells.

Proved developed producing reserves. Proved developed reserves that are expected to be recovered from completion intervals currently open in existing wells and able to produce to market.

Proved developed reserves. Proved reserves that can be expected to be recovered from existing wells with existing equipment and operating methods.

Proved reserves. The estimated quantities of crude oil, natural gas and natural gas liquids that geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under existing economic and operating conditions.

Proved undeveloped location. A site on which a development well can be drilled consistent with spacing rules for purposes of recovering proved undeveloped reserves.

Proved undeveloped reserves. 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.

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%.

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

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 commercial quantities of oil and natural gas regardless of whether such acreage contains proved reserves.

Working interest. The operating interest that gives the owner the right to drill, produce and conduct operating activities on the property and 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. Submission of Matters to a Vote of Security Holders

None.

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	53	President, Chief Executive Officer and Director
Paul F. Boling	55	Chief Financial Officer, Vice President, Secretary and Treasurer
J. Bradley Fisher	48	Vice President and Chief Operating Officer
Gregory E. Evans	59	Vice President of Exploration
Richard H. Smith	51	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.

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
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
2007		
First Quarter	$35.58	$25.54
Second Quarter	47.70	34.44
Third Quarter	46.23	34.51
Fourth Quarter	57.38	43.90

The closing market price of our common stock on March 2, 2009 was $8.73 per share. As of March 2, 2009, there were an estimated 143 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, 2003 to December 31, 2008, 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, 2003 in our common stock at the closing market price at the beginning of this period and in each of the other two indices and the reinvestment of all dividends, if any.

The graph is presented in accordance with requirements of the 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, 2003	100	100	100
December 31, 2004	109	128	157
December 31, 2005	112	196	343
December 31, 2006	128	217	403
December 31, 2007	132	277	760
December 31, 2008	81	142	224

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 2008.

Item 6. Selected Financial Data

Our financial information set forth below for each of the five years in the period ended December 31, 2008, 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,				
	2008	2007	2006	2005	2004
	(In thousands, except per share data)				
Statement Of Operations Data:					
Oil and natural gas revenues	$ 216,677	$ 125,789	$ 82,945	$ 78,155	$ 52,397
Costs and expenses:					
Oil and natural gas operating expenses	37,885	24,662	16,428	10,437	8,392
Impairment of oil and natural gas properties	138,591				
Depreciation, depletion and amortization	58,311	41,899	31,129	21,374	15,464
Third party gas purchase	6,570				
General and administrative	23,425	18,912	14,909	11,243	8,255
Accretion expense related to asset retirement	154	374	496	70	23
Total costs and expenses	264,936	85,847	62,962	43,124	32,134
Operating income (loss)	(48,259)	39,942	19,983	35,031	20,263
Gain (loss) on derivatives	37,499	(1,366)	16,457	(5,882)	(625)
Loss on extinguishment of debt	(5,689)		(294)	(3,721)	
Equity in net income/(loss) of Pinnacle Gas Resources, Inc.			35	(2,542)	(1,399)
Interest (expense) income, net of amounts capitalized and interest income	(7,636)	(13,994)	(8,127)	(4,295)	(622)
Other income and expenses, net	17	130	427	(457)	506
Income (loss) before income taxes	(24,068)	24,712	28,481	18,134	18,123
Income tax expense (benefit)	(6,129)	9,243	10,233	7,500	7,009
Income (loss) before cumulative effect of change in accounting principle	(17,939)	15,469	18,248	10,634	11,114
Dividends and accretion of discount on preferred stock					350
Net income (loss) available to common shareholders	(17,939)	15,469	18,248	10,634	10,764
Basic earnings (loss) per common share	$ (0.60)	$ 0.59	$ 0.74	$ 0.45	$ 0.54
	$ (0.60)	$ 0.57	$ 0.71	$ 0.44	$ 0.49

Diluted earnings (loss) per common share					
Basic weighted average shares outstanding	30,010	26,287	24,827	23,492	19,958
Diluted weighted average shares outstanding	30,010	27,120	25,565	24,361	21,818
Statements of Cash Flow Data:					
Net cash provided by operating activities	$ 148,754	$ 95,231	$ 65,437	$ 38,839	$ 32,501
Net cash used in investing activities	(555,345)	(227,724)	(161,576)	(111,417)	(80,294)
Net cash provided by (used in) financing activities	403,749	135,111	72,822	95,635	50,139
Other Operating Data:					
Capital expenditures	$ 571,291	$ 247,003	$ 201,773	$ 135,156	$ 83,891
Debt repayments[1]	498,239	108,258	40,536	101,021	13,737

	As of December 31,				
	2008	2007	2006	2005	2004
	(In thousands)				
Balance Sheet Data:					
Working capital (deficit)	$ (57,602)	$ (50,053)	$ (17,014)	$ 10,307	$ (8,937)
Property and equipment, net	1,021,621	646,810	445,447	314,074	205,482
Total assets	1,108,014	709,670	494,795	383,101	234,345
Long-term debt, including current maturities	533,057	254,501	188,758	149,294	62,974
Total equity	426,986	310,721	212,274	155,385	121,060

(1) Debt repayments include amounts refinanced.

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

You should read this discussion together with the consolidated financial statements and other financial information included in this Form 10-K.

General Overview

In 2008, we recognized record revenues from oil and natural gas production of $209.8 million, record production of 25.6 Bcfe and a record level of oil and gas proved reserves, at December 31, 2008, of 502.6 Bcfe. The key drivers to our success for 2008 included the following:

Drilling program. Our success is largely dependent on the results of our drilling program. During the year ended December 31, 2008, we drilled 119 gross wells (87.6 net wells) with an apparent success rate of 96% that was comprised of: (1) 80 of 80 gross wells (62.8 net wells) in the Barnett Shale area, (2) five of six gross wells (3.0 of 3.3 net wells) in the onshore Gulf Coast area, (3) 17 of 17 gross wells (17.0 net wells) in the Camp Hill Field and (4) 12 of 16 gross wells (1.4 of 4.4 net wells) in other areas. We also drilled 13 gross service wells (13.0 net wells) in the Camp Hill area and one gross appraisal well (0.2 net) in the U.K. North Sea. At December 31, 2008, 56 of these gross wells were awaiting completion or pipeline connections.

Reserve Growth. As a result of our drilling program discussed above, our reserves increased 45 percent to 502.6 Bcfe at December 31, 2008, replacing 705% of 2008 production.

Production. Our 2008 annual production of 25.6 Bcfe, or 70.0 MMcfe/d was a record high. The 2008 production increased 47% from 2007 production of 17.5 Bcfe. The increase was primarily due to the addition of new Barnett Shale wells.

Commodity prices. Our average natural gas price during 2008 was $7.80 per Mcf (excluding the impact of our hedges), $1.03 per Mcf higher than the 2007 price of $6.77. Our average oil price in 2008 was $99.74 per Bbl, or $28.32 higher than in 2007. Commodity prices are affected by changes in market demands, 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. These prices have declined significantly since mid-2008.

Capital funding. In order to fund our growth, we have taken steps to enhance our liquidity. In February 2008, we received approximately $135.1 million in net proceeds from an underwritten public offering of 2.59 million shares of our common stock. The net proceeds were used in part to pay down the $85.0 million then outstanding under our senior credit facility. In May 2008, we received net proceeds of approximately $365.3 million from the issuance of convertible notes. Part of the proceeds from the convertible notes offering were used to repay $75.0 million of outstanding debt under our senior credit facility and the $219.9 million then outstanding under our second lien credit facility. In December 2008, the borrowing base under our senior credit facility was also increased to $250.0 million. In connection with the formation of our joint venture in the Marcellus Shale play in August 2008, Avista agreed to fund 100% of the joint venture s next approximately $71.5 million of expenditures related to the play. As of December 31, 2008, Avista still had approximately $40.0 million in funding commitments remaining before we are required to fund any of our Marcellus Shale joint venture capital expenditures. After this amount has been funded, the parties will share all costs on joint venture projects in accordance with their participating interests in the properties, which we expect will be generally 50/50. We currently expect that substantially all of our capital and exploration expenditures of our joint venture in the Marcellus Shale during 2009 will be met through Avista s funding obligation.

Outlook for 2009

Our outlook for 2009 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 stable upward movement in commodity prices are key to our future success, and we believe the following measures will have a positive impact on our results in 2009:

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 current economic downturn and the current cost of accessing the capital markets, we have reduced our approved capital and exploration budget for 2009 to $105.0 million, and we are striving to maintain our financial flexibility and a positive production growth profile. Further deterioration in commodity prices may cause us to reduce our capital and exploration budget for 2009 even further.

2009 drilling and capital program. In 2009 we plan to drill 45 gross (30.0 net) wells in the Barnett Shale area, 12 gross (4.0 net) wells in the Marcellus Shale play area, three gross (1.0 net) wells in the Gulf Coast area and to complete 44 gross (44.0 net) wells in the Camp Hill Field. As mentioned above, our 2009 capital and exploration budget has been reduced to approximately $105 million and includes approximately $90.0 million for drilling, comprised in Barnett Shale ($85.0 million), Gulf Coast ($3.0 million) and Camp Hill ($2.0 million). We also plan to spend $3.0 million in the U.K. North Sea, largely for pre-development project costs, and approximately $12.0 million for land and seismic activities, most of it in the Barnett Shale. We currently expect that our land acquisition, exploration and drilling program in the Marcellus will be funded by Avista under our joint venture agreement. 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, 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 Period Compared to 2007 Period	
	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 2,467.6 and 1,316.3 Mmcfe of natural gas liquids in 2008 and 2007, respectively.

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 $138.6 million ($90.1 million after tax).

Depreciation, depletion and amortization (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.

General and administrative (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 net loss on derivatives.

Interest expense and capitalized interest in 2008 were $23.5 million and $15.6 million, respectively, as compared to $26.4 million and $11.7 million in 2007. These decreases was largely attributable to the pay off 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. These decreases were partially offset by increased debt outstanding during 2008.

Year Ended December 31, 2007 Compared to the Year Ended December 31, 2006

Oil and natural gas revenues for 2007 increased 52% to $125.8 million from $82.9 million in 2006. Production volumes for oil and natural gas in 2007 increased 49% to 17.5 Bcfe from 11.7 Bcfe in 2006. Realized average natural gas sales price for 2007 increased 3% to $6.77 per Mcf compared to $6.56 per Mcf in 2006, and the average oil sales price for 2007 increased 12% to $71.42 per barrel from $63.62 per barrel in 2006. The increase in natural gas production was primarily due to the production from new wells in the Barnett Shale area and the Baby Ruth and Doberman #1 wells in the Gulf Coast 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, 2007 and 2006:

	December 31,		2007 Period Compared to 2006 Period	
	2007	2006	Increase (Decrease)	% Increase (Decrease)
Production volumes-				
Oil and condensate (Mbbls)	241	255	(14)	(5)%
Natural gas (MMcf)[(1)]	16,042	10,176	5,866	58%
Average sales prices-				
Oil and condensate (per Bbl)	$ 71.42	$ 63.62	$ 7.80	12%
Natural gas (per Mcf)	6.77	6.56	0.21	3%
Operating revenues (In thousands) -				
Oil and condensate	$ 17,197	$ 16,217	$ 980	6%
Natural gas	108,592	66,728	41,864	63%
Total	$ 125,789	$ 82,945	$ 42,844	52%

(1) Includes 1,316.3 Mmcfe of natural gas liquids in 2007.

Oil and natural gas operating expenses for 2007 increased 50% to $24.7 million (or $1.41 per Mcfe) from $16.4 million (or $1.40 per Mcfe) in 2006. While total costs increased primarily due to increased production, costs per Mcfe remained relatively unchanged from 2006 to 2007. The increase in total operating expenses was due to (i) approximately $3.3 million in higher transportation gathering and treating costs in the Barnett Shale, (ii) higher saltwater disposal costs of $2.2 million, (iii) increased compression costs of $1.1 million, (iv) higher severance taxes of $0.9 million and (v) increased workover expenses of $0.4 million.

DD&A expense for 2007 increased 35% to $41.9 million from $31.1 million in 2006. 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 2007.

G&A expense for 2007 increased 27% to $18.9 million from $14.9 million for 2006. The increase in G&A was due primarily to (i) increased employee related costs of $2.5 million, (ii) increased stock-based compensation expense of $2.0 million due to additional restricted shares issued in 2007 and higher stock prices (iii) increased office expense of $0.6 million and (iv) increased legal and professional fees of $0.3 million. These increases were partially offset by decreased bad debt expense of $1.4 million primarily related to a 2006 outside operator bankruptcy filing.

The net loss on derivatives was $1.4 million for the year ended December 31, 2007, comprised of (i) $7.4 million of unrealized mark-to-market net losses on derivatives ($4.6 million loss on oil and gas derivatives and $2.8 million loss on interest rate swaps) and (ii) $6.0 million of net realized gains ($5.8 million gain from oil and gas derivatives and $0.2 million gain from interest rate swaps).

Interest expense and capitalized interest in 2007 were $26.4 million and $11.7 million, respectively, as compared to $19.1 million and $10.0 million in 2006. These increases were attributable to the $75.0 million increase in borrowings under the Second Lien Credit Facility in January 2007, increased borrowings under our senior credit facility and higher effective interest rates.

Liquidity and Capital Resources

2009 Capital Budget and Funding Strategy. For 2009, our Board has established a capital and exploration expenditures budget of $105 million, including (i) $90 million for our drilling program (including $85 million for the Barnett Shale development), (ii) $3 million for pre-development project costs in the U.K. North Sea (iii) $6 million for lease acquisitions, primarily in the Barnett Shale and (iv) $6 million for seismic data acquisition. We intend to finance our 2009 capital and exploration budget primarily from oil and natural gas production sales revenue, supplemented by borrowings under our senior credit facility and the possible selective sale of non-core assets. We may be required to reduce or defer part of our 2009 capital expenditures program if we are unable to obtain sufficient financing from these sources.

Sources and Uses of Cash. During the year ended December 31, 2008, capital expenditures, net of proceeds from property sales, exceeded our net cash provided by operations. During 2008, we funded our capital expenditures with cash generated from operations, proceeds from the issuance of our common stock and convertible notes, and net additional borrowings under our 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.

Available borrowings under our senior credit facility. During the fourth quarter of 2008, the borrowing base under our senior credit facility increased to $250.0 million. At March 2, 2009, $71.0 million was available for borrowing under our senior credit facility. The next borrowing base redetermination is currently scheduled for March 31, 2009.

Other debt and equity offerings. In February 2008, we received $135.1 million of net proceeds from an underwritten public offering of 2,587,500 shares of our common stock priced at $54.50 per share. In May 2008, we received $365.3 million of net proceeds from the issuance of our convertible notes. 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.

Asset sales. In order to fund our capital and exploration budget, we may consider the sale of certain properties or assets that are not part of our core business, can be monetized at a price we find acceptable, or are no longer deemed essential to our future growth.

Project financing in certain limited circumstances.

Lease option agreements and land banking arrangements, such as those we have entered into regarding 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 recent joint venture in the Marcellus Shale play.

We may consider sale/leaseback transactions of certain capital assets, such as 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 acquisition programs. Our capital expenditures budget in 2009 provides for approximately $90 million for drilling, and approximately $12 million for lease and seismic acquisitions. In 2009 we currently plan to drill 45 gross (30.0 net) wells in the Barnett Shale area, three gross (1.0 net) wells in the Gulf Coast area, and to complete 44 gross (44.0 net) wells in the Camp Hill Field, and to spend approximately $3.0 million on project development in the Huntington Field in the U.K. North Sea and in other areas. The actual number of wells drilled and capital expended is dependent upon 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 $148.8 million, $95.2 million and $65.4 million for the years ended December 31, 2008, 2007 and 2006, respectively. The increase from 2007 to 2008 was primarily due to an increase in revenues largely attributable to a 47% increase in production. Natural gas prices have fallen since the third quarter of 2008 and have generally continued to decline into 2009, having a negative impact on our cash flow from operations and on our 2009 drilling plans. Despite our increase in natural gas production a continued fall in natural gas prices could have a further negative impact on our cash flow from operations and on our 2009 drilling plans.

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. Cash flows used in investing activities were $227.7 million for the year ended December 31, 2007 and related primarily to oil and gas property expenditures. Cash flows used in investing activities of $161.6 million for the year ended December 31, 2006 were largely attributable to capital expenditures for oil and gas properties of $201.8 million partially offset by proceeds from the sale of properties of $38.3 million.

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 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. Net cash provided by financing activities for the year ended December 31, 2006 was $72.8 million and related primarily to additional borrowings under our senior credit facility of $80.0 million and net proceeds of $33.5 million from the issuance of common stock, partially offset by $40.5 million of debt repayments.

Liquidity/Cash Flow Outlook.

We currently believe that cash generated from operations, supplemented by borrowings under our 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 third quarter of 2008. In an effort to mitigate declining prices, we hedge a portion of our production and, as of March 3, 2009, we have hedged approximately 25,570,000 MMBtu (70 MMcf per day for the year, or 85% of our estimated production from April through December 2009) of our 2009 natural gas production at a weighted average floor or swap price of $6.20 per MMBtu relative to WAHA and Houston Ship Channel prices. We believe the funds available to us under our senior credit facility, $71.0 million at March 2, 2009, will be accessible to us. We are scheduled for a borrowing base redetermination on March 31, 2009 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 2008. 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 and these may result in a lower borrowing base 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 and funds available under our senior credit facility are insufficient to fund our 2009 capital and exploration budget, we may need to reduce our capital and exploration budget 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 2009 natural gas and oil exploration and development program, thereby adversely affecting the recoverability and ultimate value of our natural gas and oil properties. The recent worldwide financial and credit crisis has adversely affected our ability to access the capital markets.

Contractual Obligations

The following table sets forth estimates of our contractual obligations as of December 31, 2008:

	Payments Due by Year (In thousands)					
	Total	2009	2010	2011	2012	2013 and Thereafter
Long-term Debt	$ 533,230	$ 173	$ 148	$ 159	$ 159,000	$ 373,750
Operating Leases	3,212	1,008	1,102	1,102		
Drilling Contracts	58,937	25,294	25,295	8,348		
Pipeline Volume Commitment[(1)]	46,976	6,273	7,144	6,479	5,857	21,223
Total Contractual Cash Obligations	$ 642,355	$ 32,748	$ 33,689	$ 16,088	$ 164,857	$ 394,973

(1) Includes a seven firm year transportation agreement for 80,000 MMBtus/d with an estimated starting date in October 2009.

Off Balance Sheet Arrangements

We currently do not have any off balance sheet arrangements.

Financing Arrangements

Senior Secured Revolving Credit Facility

On May 25, 2006, we entered into a Senior Secured Revolving Credit Facility (Senior Credit Facility) with JPMorgan Chase Bank, National Association, as administrative agent. The Senior Credit Facility provided for a revolving credit facility up to the lesser of the borrowing base and $200.0 million. It is secured by substantially all of our proved oil & gas assets and is guaranteed by our subsidiaries CCBM, Inc., CCLR, Inc., Carrizo (Marcellus) LLC and Carrizo Marcellus Holding Inc.

In the fourth quarter of 2008, we amended the Senior Credit Facility to (1) increase the borrowing base to $250.0 million; (2) extend the maturity date to October 29, 2012; (3) increase the maximum total net debt to Consolidated EBITDAX to 4.0 to 1.0; (4) change the semi-annual borrowing base redetermination dates to March 31 and September 30; (5) change the interest rate provisions; and (6) replace JPMorgan Chase with Guaranty Bank as the administrative agent bank.

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 0.75% and 2.25% (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 2.0% to 3.5% (depending on the current level of borrowing base usage). The interest rate on each Eurodollar loan is the adjusted daily LIBO rate plus a margin between 2.0% to 3.5% (depending on the then-current level of borrowing base usage). At February 17, 2009, the average interest rate for amounts outstanding under the Senior Credit Facility was 3.4%.

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 1.0 to 1.0; and (2) a maximum total net debt to Consolidated EBITDAX (as defined in the Senior Credit Facility) of 4.0 to 1.0. Although we currently believe that we can comply with 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 in our 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 budget, sell non-strategic assets, opportunistically modify or increase our natural gas hedges or approach the lenders under our 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 our 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, 2008, we were in compliance with all of our debt covenants.

As of March 2, 2009, we had $179.0 million of borrowings outstanding and a borrowing base availability of $71.0 million.

Convertible Senior Notes

In May 2008, we issued $373.8 million aggregate principal amount of 4.375% convertible senior notes due 2028 (Convertible Senior Notes). Interest is payable on June 1 and December 1 each year, commencing December 1, 2008. 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 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 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.

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; and Private Placement of Common Stock in 2006.

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 borrowings then outstanding under the Senior Credit Facility. We used the remaining proceeds to fund in part 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 $72.0 million of net proceeds. We used the net proceeds to repay $54 million of outstanding borrowings under the Senior Credit Facility and to fund in part our 2007 capital expenditure program.

In July 2006, we sold 1,350,000 shares of our common stock to institutional investors at a price of $26.00 per share in a private placement (the 2006 Private Placement). The net proceeds, after deducting placement agents fees but before paying offering expenses, of approximately $33.7 million were principally used to fund a portion of our 2006 capital expenditures program. In connection with the 2006 Private Placement, we entered into Subscription and Registration Rights Agreements (the Subscription and Registration Rights Agreements) with the investors in the 2006 Private Placement. The Subscription and Registration Rights Agreements provide registration rights with respect to the shares purchased in the 2006 Private Placement. We filed a resale shelf registration statement in connection with the 2006 Private Placement that has been declared effective by the Commission. We are generally subject to specified penalties in the event we do not maintain the effectiveness of the registration statement. We are subject to certain covenants under the terms of the Subscription and Registration Rights Agreements, including the requirement that the registration statement be kept effective for resale of shares for two years. In certain situations, we are required to indemnify the investors in the 2006 Private Placement, including without limitation, for certain liabilities under the Securities Act.

Lease Option Arrangements

Due to the limited capital available at times to fund all of our ongoing lease acquisition efforts in the Barnett Shale, Marcellus Shale, Fayetteville Shale and other plays, we elect from time to time to enter into various lease purchase option agreements with a number of third parties, including, in 2006, Steven A. Webster, who is the Chairman of our Board of Directors. The lease purchase option arrangement with Mr. Webster expired at the end of 2006. The terms and conditions of the lease purchase option arrangement with Mr. Webster were consistent with the lease purchase option arrangements we entered into with unrelated third parties. These lease purchase option arrangements provide us the option to purchase leases from the counterparties, over an option period, generally 90 days, for the counterparties original cost of the leases plus an option fee. We paid Mr. Webster fees totaling approximately $250,000 in 2006. In accordance with the lease purchase option agreement, we also assigned to him an overriding royalty interest on any lease we acquired from Mr. Webster under the lease purchase option agreement with him, which overriding royalty interest varied from one-half to one percent of 8/8ths, proportionally reduced to the actual net interest in any given lease acquired from Mr. Webster. We paid Mr. Webster approximately $430 and $50 in 2008 and 2007, respectively, for overriding royalties under these 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.

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 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.

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 in 2008 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 the government attempting to stimulate the economy through rapid expansion of the money supply in recent months, inflation could become a significant issue in the future.

Recently Issued Accounting Pronouncements

In March 2008, the Financial Accounting Standards Board (FASB) issued SFAS No. 161, *Disclosures about Derivative Instruments and Hedging Activities* (SFAS No. 161). This standard is intended to improve financial reporting by requiring 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 under SFAS No. 133, and how derivative instruments and related hedged items affect an entity s financial position, financial performance and cash flows. The provisions of SFAS No. 161 are effective for financial statements issued for fiscal years and interim periods beginning after November 15, 2008. We do not believe the adoption of SFAS No. 161 will have a significant effect on our consolidated financial position, results of operations or cash flows.

In May 2008, the FASB issued FASB Staff Position (FSP) Accounting Principles Board (APB) 14-1, *Accounting for Convertible Debt Instruments That May Be Settled in Cash upon Conversion* (*Including Partial Cash Settlement*). This FSP clarifies that convertible debt instruments that may be settled in cash upon conversion, including partial cash settlement, are not addressed by paragraph 12 of APB Opinion No. 14, *Accounting for Convertible Debt and Debt Issued with Stock Purchase Warrants.* Additionally, this FSP specifies that issuers of such instruments should separately account for the liability and equity components in a manner that will reflect the entity s nonconvertible debt borrowing rate when interest cost is recognized in subsequent periods. This FSP is effective for financial statements issued for fiscal years beginning after December 15, 2008 and early adoption is not permitted. We currently expect to value the 4.375% Senior Convertible Notes due 2028 as $309.6 million of debt and $64.2 million of equity representing the fair value of the conversion premium. Our effective interest rate is expected to be approximately 8%. After implementation of this standard, the FSP requires retrospective application which is expected to increase the Company s 2008 interest expense by approximately $6 million and increase the Company s future interest expense by approximately $12 million annually through May 2013 before consideration of any amounts that may be capitalized.

In June 2008, the FASB issued FSP Emerging Issues Task Force (EITF) 03-6-1, *Determining Whether Instruments Granted in Share-Based Payment Transactions Are Participating Securities.* This FSP provides that 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. We do not currently expect the adoption of this FSP to have a material impact to our consolidated financial statements and disclosures.

On December 31, 2008, the Securities and Exchange Commission (SEC) adopted major revision to its rules governing oil and gas company reporting requirements. These include provisions that permit the use of new technologies to determine proved reserves and that allow companies to disclose their probable and possible reserves to investors. The current rules limit disclosure to only proved reserves. The new disclosure requirements also require companies to report the independence and qualification of the person primarily responsible for the preparation or audit of reserve estimates, and to file reports when a third party is relied upon to prepare or audit reserves estimates. The new rules also require that the present value of oil and gas reserves be reported and to be used in the full-cost ceiling test calculation be based upon an average price for the prior 12-month period. The new oil and gas reporting requirements are effective for annual reports on Form 10-K for fiscal years ending on or after December 31, 2009, with early adoption not permitted. The Company is in the process of assessing the impact of these new requirements on its financial position, results of operations and financial disclosures.

Recently Adopted Accounting Pronouncements

We adopted the Statement of Financial Accounting Standards No. 157, *Fair Value Measurement* (SFAS No. 157), effective January 1, 2008. SFAS No. 157 provides a framework for measuring fair value and enhances related disclosures. The implementation of SFAS No. 157 did not change our current valuation method and did not have a material effect on our consolidated financial position or results of operations. We included additional disclosures in the Notes to Consolidated Financial Statements with respect to the measurement of our assets and liabilities at fair value on the balance sheet date.

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.

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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 estimate. 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 natural gas and oil properties. We capitalized compensation costs and other costs for employees working directly on exploration activities of $7.8 million, $4.5 million and $3.5 million in 2008, 2007 and 2006, respectively. We expense maintenance and repairs as they are incurred.

We amortize natural gas and oil properties based on the unit-of-production method using estimates of proved reserve quantities. We do not amortize investments in unproved properties until proved reserves associated with the projects can be determined or until these investments are impaired. We periodically evaluate, on a property-by-property basis, unevaluated properties for impairment. If the results of an assessment indicate that the properties are impaired, we add the amount of impairment to the proved natural gas and oil property costs to be amortized. The amortizable base includes estimated future development costs and, where significant, dismantlement, restoration and abandonment costs, net of estimated salvage values. The depletion rate per Mcfe for 2008, 2007 and 2006 was $2.23, $2.36 and $2.61, respectively.

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.

The net capitalized costs of proved oil and natural gas properties are limited to a ceiling test based on the estimated future net revenues, discounted at a 10% per annum, from proved oil and natural gas reserves based on current economic and operating conditions (the Full Cost Ceiling). If net capitalized costs exceed this limit, the excess is charged to earnings.

The Full Cost Ceiling impairment at the end of 2008 of approximately $138.6 million was based upon average realized oil, natural gas liquids and natural gas prices of $40.12 per Bbl, $19.62 per Bbl and $4.99 per Mcf, respectively, or a volume weighted average price of $29.86 per BOE. We would not have had a Full Cost Ceiling write-down at an estimated volume weighted average price of $36.11 per BOE. The Full Cost Ceiling impairment was primarily the result of the decline in commodity prices. The prices used in the ceiling test impairment were the prices in effect at December 31, 2008, as contemplated by current Commission rules that require the use of prices in effect on the last day of the relevant financial period. These rules are expected to change in the future to require the use of an average price over a twelve-month period.

Under the full cost method of accounting, the depletion rate is the current period production as a percentage of the total proved 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 unevaluated costs) and estimated future development costs less net 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 have a significant amount of proved undeveloped reserves. We had 239.1 Bcfe, 185.8 Bcfe and 126.2 Bcfe of proved undeveloped reserves, representing 48%, 53% and 60% of our total proved reserves at December 31, 2008, 2007 and 2006, respectively. As of December 31, 2008, less than 13% of these proved undeveloped reserves, or approximately, 29.9 Bcfe, were attributable to our Camp Hill properties that we acquired in 1994. See Business and Properties¯Significant Project Areas Camp Hill Area for further discussion of the Camp Hill properties. The estimated future development costs to develop our proved undeveloped reserves on our Camp Hill properties are relatively low, on a per Mcfe basis, when compared to the estimated future development costs to develop our proved undeveloped reserves on our other oil and natural gas properties. Furthermore, the average depletable life (the estimated time that it will take to produce all recoverable reserves) of our Camp Hill properties is considerably longer, or approximately 15 years, when compared to the depletable life of our remaining oil and natural gas properties of approximately 10 years. Accordingly, the combination of a relatively low ratio of future development costs and a relatively long depletable life on our Camp Hill properties has resulted in a relatively low overall historical depletion rate and DD&A expense. This has resulted in a capitalized cost basis associated with producing properties being depleted over a longer period than the associated production and revenue stream, causing the build-up of non-depleted capitalized costs associated with properties that have been completely depleted. This combination of factors, in turn, has had a favorable impact on our earnings, which have been higher than they would have been had the Camp Hill properties not resulted in a relatively low overall depletion rate and DD&A expense and longer depletion period. As a hypothetical illustration of this impact, the removal of our Camp Hill proved undeveloped reserves starting January 1, 2002 would have reduced our net income by, (1) an estimated $11.2 million in 2002 (comprised of after-tax charges for a $7.1 million full cost ceiling impairment and a $4.1 million depletion expense increase), (2) an estimated $5.9 million in 2003 (due to higher depletion expense), (3) an estimated $3.4 million in 2004 (due to higher depletion expense), (4) an estimated $6.9 million in 2005 (due to higher depletion expense), (5) an estimated $0.7 million in 2006 (due to higher depletion expense), (6) an estimated $2.0 million in 2007 (due to higher depletion expenses) and (7) an estimated $11.7 million in 2008 (comprised of after-tax charges for a $11.0 million full cost ceiling impairment and a $0.7 million depletion expense increase).

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, 2008 included in this document are estimates prepared by Ryder Scott Company, LaRoche Petroleum Consultants, Ltd., and Fairchild & Wells, 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. 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 prices 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 is dependent 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 nine percent for the year ended December 31, 2008.

As of December 31, 2008, approximately 58% 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, 2008 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 certainty with respect to development plans for proved undeveloped reserves could cause the discontinuation of the classification of these reserves as proved. We have from time to time chosen to delay development of our proved undeveloped reserves in the Camp Hill Field in East Texas in favor of pursuing shorter-term exploration projects with higher potential rates of return, adding to our lease position in this field and further evaluating additional economic enhancements for this field s development. The average life of the Camp Hill proved undeveloped reserves is approximately 15 years, with 50% of these reserves being booked over ten years ago. Although we have increased the pace of the development of the Camp Hill project, there can be no assurance that the aforementioned discontinuance will not occur.

Derivative Instruments

We use derivatives, typically fixed-rate swaps and costless collars, 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. We have elected to account for our derivative contracts as non-designated derivatives that will be marked-to-market. 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.

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.

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 at December 31, 2008, 2007 and 2006 were treated as non-designated derivatives and the unrealized gains related to the mark-to-market valuation was included in our earnings.

Income Taxes

Under Statement of Financial Accounting Standards No. 109 (SFAS No. 109), *Accounting for 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. We consider future taxable income 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, it is 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, which when analyzed indicates that 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 engage periodically in certain other limited derivative activities including price swaps, costless collars and, occasionally, put options, in order to establish some price floor protection. 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, 2008, 2007 and 2006 and the unrealized gain (loss) associated with the outstanding oil and natural gas derivatives at December 31, 2008, 2007 and 2006.

	December 31,		
	2008	**2007**	**2006**
Oil positions settled (Bbls)	64,100	52,000	82,200
Natural gas positions settled (MMBtu)	15,733,000	7,846,000	5,481,000
Realized gain ($ millions) [(1)]	$ 0.6	$ 5.8	$ 6.8
Unrealized gain (loss) ($ millions) [(1)]	$ 38.6	$ (4.6)	$ 8.7

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

At December 31, 2008, approximately 69% of our open natural gas hedges were with Credit Suisse and the remaining 31% were with Shell Energy North America (US), L.P. The open oil hedges were with Credit Suisse.

While the use of hedging arrangements 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 two 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 again 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 hedging transaction. Moreover, our derivative 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. Our oil derivative transactions are generally settled based on the average reporting settlement prices on the West Texas Intermediate index for each trading day of a particular calendar month.

At December 31, 2008 we had the following open derivative positions:

	Natural Gas Swaps		Natural Gas Collars			Basis Differential Swaps(2)	
Quarter	MMbtu	Average Fixed Price(1)	MMBtu	Average Floor Price(1)	Average Ceiling Price(1)	MMBtu	Price
First Quarter 2009	2,803,000	$ 6.13	2,520,000	$ 7.37	$ 9.10	310,000	$0.31
Second Quarter 2009	1,547,000	5.40	2,548,000	7.12	8.85		
Third Quarter 2009			2,576,000	7.16	8.88	920,000	0.31
Fourth Quarter 2009			2,576,000	7.17	8.90		
First Quarter 2010			1,620,000	7.92	9.63		
Second Quarter 2010			1,638,000	7.18	8.89		
Third Quarter 2010			1,656,000	7.35	9.06		
Fourth Quarter 2010			1,656,000	7.45	9.16		
First Quarter 2011			450,000	9.70	11.70		
Second Quarter 2011			455,000	8.25	10.25		
Third Quarter 2011			460,000	8.65	10.65		
Fourth Quarter 2011			460,000	8.85	10.85		
First Quarter 2012			455,000	9.55	11.55		
Second Quarter 2012			455,000	8.35	10.35		
TOTAL	4,350,000		19,525,000			1,230,000	

		Oil Collars	
Quarter	Bbls	Average Floor Price(3)	Average Ceiling Price(3)
First Quarter 2009	9,000	$ 131.65	$ 151.65
Second Quarter 2009	9,100	131.40	151.40
Third Quarter 2009	9,200	130.85	150.85
Fourth Quarter 2009	9,200	130.35	150.35
TOTAL	36,500		

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

(2) Basis differential swaps cover the price differential for natural gas between NYMEX and HSC.

(3) Based on West Texas intermediate index prices.

In the first quarter of 2009, in order to monetize some profitable hedge positions, we sold down a portion of our oil hedge positions, receiving $2.2 million in proceeds. We also converted a 2010 natural gas costless collar position into a 2009 natural gas fixed price swap to further mitigate the risk of declining natural gas prices in 2009. As of March 2, 2009, we had the following open derivative positions:

	Natural Gas Swaps		Natural Gas Collars			Basis Differential Swaps(2)	
Quarter	**MMbtu**	**Average Fixed Price(1)**	**MMBtu**	**Average Floor Price(1)**	**Average Ceiling Price(1)**	**MMBtu**	**Price**
First Quarter 2009	2,803,000	$ 6.13	2,520,000	$ 7.37	$ 9.10		$
Second Quarter 2009	5,187,000	5.34	2,548,000	7.12	8.85		
Third Quarter 2009	3,680,000	5.31	2,576,000	7.16	8.88	920,000	0.31
Fourth Quarter 2009	3,680,000	5.58	2,576,000	7.17	8.90		
First Quarter 2010	1,800,000	5.57	1,620,000	7.92	9.63		
Second Quarter 2010	1,820,000	5.57	182,000	7.35	9.15		
Third Quarter 2010	1,840,000	5.57	184,000	7.35	9.15		
Fourth Quarter 2010	1,840,000	5.57	184,000	7.35	9.15		
First Quarter 2011	1,800,000	5.64	450,000	9.70	11.70		
Second Quarter 2011	1,820,000	5.64	455,000	8.25	10.25		
Third Quarter 2011	1,840,000	5.64	460,000	8.65	10.65		
Fourth Quarter 2011	1,840,000	5.64	460,000	8.85	10.85		
First Quarter 2012	910,000	5.88	455,000	9.55	11.55		
Second Quarter 2012	910,000	5.88	455,000	8.35	10.35		
Third Quarter 2012	920,000	5.88					
Fourth Quarter 2012	920,000	5.88					
TOTAL	33,610,000		15,125,000			920,000	

(1) Based on Houston Ship Channel and

WAHA spot prices.

(2) Basis differential swaps cover the price differential for natural gas between NYMEX and HSC.

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 $21.0 million impact on our 2008 annual revenues.

To mitigate some of this risk, we engage periodically in certain limited hedging activities, including price swaps, costless collars and, occasionally, put options, in order to establish some price floor protection. Costs and any benefits derived from these price floors are accordingly recorded as a reduction or increase, as applicable, in oil and gas sales revenue and were not significant for any year presented. The costs to purchase put options are amortized over the option period. We do not hold or issue derivative instruments for trading purposes. The net gain realized by us related to these instruments was $0.6 million, $5.8 million and $6.8 million the years ended December 31, 2008, 2007 and 2006, 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, 2008 and 2007, and were determined based upon interest rates currently available to us for borrowings with similar terms. Maturities of long-term debt are $0 in 2010 and 2011, and $159.0 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 In and Disagreements With Accountants on Accounting and Financial Disclosure

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 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 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 and 15d-15, we carried out an evaluation, under the supervision and with the participation of management, including our Chief Executive Officer (CEO) and Chief Financial Officer (CFO), of the effectiveness of our disclosure controls and procedures as of the end of the period covered by this report. As described below under Management s Annual Report on Internal Control over Financial Reporting, our CEO and CFO have concluded that, as of the end of the period covered by this Annual Report on Form 10-K, the Company s disclosure controls and procedures were effective to provide reasonable assurance that information required to be disclosed in our reports filed or submitted under the Exchange Act is recorded, processed, summarized and reported within the time periods specified in the Commission s rules and forms provided, that we were required to seek relief under Rule 12b-25 in connection with the filing of this Annual Report on Form 10-K to obtain additional time to complete the financial statements and secondary reviews needed to finalize our Annual Report on Form 10-K due to an impairment to oil and gas properties as a result of a decline in prices for natural gas and oil.

Pannell Kerr Forster of Texas, P.C. s audit report, dated March 12, 2009, expressed an unqualified opinion on our consolidated financial statements and its Report of Independent Registered Public Accounting Firm is included herein at page F-3.

(b) Management s Annual Report on Internal Control over Financial Reporting.

Management of the Company 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 Securities Exchange Act of 1934, as amended. The Company s 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. The 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 the 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.

Management assessed the effectiveness of the Company s internal control over financial reporting as of December 31, 2008. In making this assessment, management used the criteria set forth by the Committee of Sponsoring Organizations of the Treadway Commission in *Internal Control-Integrated Framework*.

Based on such assessment and those criteria, management believes that the Company maintained effective internal control over financial reporting as of December 31, 2008.

Pannell Kerr Forster of Texas, P.C., our independent registered public accounting firm who also audited the Company s consolidated financial statements, has issued its own attestation report on management s assessment of the effectiveness of the Company s internal control over financial reporting as of December 31, 2008, which is filed herewith.

(c) Changes in Internal Control over Financial Reporting. There have not been any changes in the Company s internal control over financial reporting during the fiscal quarter ended December 31, 2008 that have materially affected, or are reasonably likely to materially affect, the Company s 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 2009 Proxy Statement) for our 2009 annual meeting of shareholders. The 2009 Proxy Statement will be filed with the Commission (the Commission) not later than 120 days subsequent to December 31, 2008.

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 2009 Proxy Statement, which will be filed with the Commission not later than 120 days subsequent to December 31, 2008.

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 2009 Proxy Statement, which will be filed with the Commission not later than 120 days subsequent to December 31, 2008.

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

The information required by this item is incorporated herein by reference to the 2009 Proxy Statement, which will be filed with the Commission not later than 120 days subsequent to December 31, 2008.

Item 14. Principal Accountant Fees and Services

The information required by this item is incorporated by reference to the 2009 Proxy Statement, which will be filed with the Commission not later than 120 days subsequent to December 31, 2008.

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

SCHEDULE II
Carrizo Oil & Gas, Inc.
VALUATION AND QUALIFYING ACCOUNTS
Years Ended December 31, 2008, 2007 and 2006
(In thousands)

Description	Balance at Beginning of Period	Charged to Costs and Expenses	Deductions	Charged to Other Accounts	Balance at End of Period
2008					
Allowance for doubtful accounts	$1,430	$ (166)	$	$	$1,264
2007					
Allowance for doubtful accounts	$1,639	$ (209) (1)	$	$	$1,430
2006					
Allowance for doubtful accounts	$ 253	$1,386(2)	$	$	$1,639

(1) Relates primarily to an adjustment of the 2006 bankruptcy filing by an outside operator.

(2) Relates primarily to a bankruptcy filing by an outside operator.

(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, 1998).
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).
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 February 17, 2000 (incorporated herein by reference to Exhibit 10.3 to the Company s Quarterly Report on Form 10-Q for the quarter ended June 30, 2000).

Exhibit Number	Description
* 10.3	Amendment No. 1 to the Amended and Restated Incentive Plan of the Company (incorporated herein by reference to Exhibit 10.1 to the Company s Quarterly Report on Form 10-Q for the quarter ended June 30, 2002).
* 10.4	Amendment No. 2 to the Amended and Restated Incentive Plan of the Company (incorporated herein by reference to Exhibit 10.3 to the Company s Annual Report on Form 10-K for the year ended December 31, 2002).
* 10.5	Amendment No. 3 to the Amended and Restated Incentive Plan of the Company (incorporated herein by reference to Appendix A to the Company s Proxy Statement dated April 21, 2003).
* 10.6	Amendment No. 4 to the Amended and Restated Incentive Plan of the Company (incorporated herein by reference to Appendix B to the Company s Proxy Statement dated April 26, 2004).
* 10.7	Amendment No. 5 to the Amended and Restated Incentive Plan of the Company (incorporated herein by reference to Exhibit 10.1 to the Company s Current Report on Form 8-K filed on May 16, 2005).
* 10.8	Amendment No. 6 to the Amended and Restated Incentive Plan of the Company (incorporated herein by reference to Exhibit 10.1 to the Company s Current Report on Form 8-K filed on August 19, 2005).
* 10.9	Amendment No.7 to the Amended and Restated 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 May 30, 2006).
* 10.10	Employment Agreement between the Company and S.P. Johnson IV (incorporated herein by reference to Exhibit 10.2 to the Company s Registration Statement on Form S-1 (Registration No. 333-29187)).
* 10.11	Employment Agreement between the Company and J. Bradley Fisher (incorporated herein by reference to Exhibit 10.8 to the Company s Registration Statement on Form S-2 (Registration No. 333-111475)).
* 10.12	Employment Agreement between the Company and Paul F. Boling (incorporated herein by reference to Exhibit 10.9 to the Company s Registration Statement on Form S-2 (Registration No. 333-111475)).
* 10.13	Employment Agreement between the Company and Gregory E. Evans dated March 21, 2005 (incorporated herein by reference to Exhibit 10.1 to the Company s Current Report on Form 8-K filed on March 22, 2005).
* 10.14	Employment Agreement between Carrizo Oil & Gas, Inc. and Richard Smith dated September 18, 2006, and effective as of August 23, 2006 (incorporated herein by reference to Exhibit 10.1 to the Company s Current Report on Form 8-K filed on September 22, 2006).
* 10.15	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).
* 10.16	Form of Amendment to Executive Officer Employment Agreement (incorporated herein by reference to Exhibit 99.3 to the Company s Current Report on Form 8-K dated January 8, 1998).
* 10.17	Form of Amendment to Executive Officer Employment Agreement (incorporated herein by reference to Exhibit 99.7 to the Company s Current Report on Form 8-K dated December 15, 1999).
* 10.18	Form of Amendment to Director Indemnification Agreement (incorporated herein by reference to Exhibit 99.8 to the Company s Current Report on Form 8-K dated December 15, 1999).
* 10.19	Form of Amendment to Executive Officer Employment Agreement (incorporated herein by reference to Exhibit 99.7 to the Company s Current Report on Form 8-K dated February 20, 2002).
* 10.20	Form of Amendment to Director Indemnification Agreement (incorporated herein by reference to Exhibit 99.8 to the Company s Current Report on Form 8-K dated February 20, 2002).
* 10.21	Amendment to the Employment Agreement between the Company and S.P. Johnson IV (incorporated herein by reference to Exhibit 10.1 to the Company s Current Report on Form 8-K filed on

		January 27, 2006).
*	10.22	Amendment to the Employment Agreement between the Company and Paul F. Boling (incorporated herein by reference to Exhibit 10.2 to the Company s Current Report on Form 8-K filed on January 27, 2006).
*	10.23	Amendment to the Employment Agreement between the Company and Gregory E. Evans (incorporated herein by reference to Exhibit 10.3 to the Company s Current Report on Form 8- K filed on January 27, 2006).

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Exhibit Number	Description
* 10.24	Amendment to the 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 January 27, 2006).
* 10.25	Amendment to the Employment Agreement between Carrizo Oil & Gas, Inc. and S.P. Johnson IV effective December 19, 2008 (incorporated herein by reference to Exhibit 10.1 to the Company s Current Report on Form 8-K filed on December 23, 2008).
* 10.26	Amendment to the Employment Agreement between Carrizo Oil & Gas, Inc. and Paul F. Boling effective December 19, 2008 (incorporated herein by reference to Exhibit 10.2 to the Company s Current Report on Form 8-K filed on December 23, 2008).
* 10.27	Amendment to the Employment Agreement between Carrizo Oil & Gas, Inc. and J. Bradley Fisher effective December 19, 2008 (incorporated herein by reference to Exhibit 10.3 to the Company s Current Report on Form 8-K filed on December 23, 2008).
* 10.28	Amendment to the Employment Agreement between Carrizo Oil & Gas, Inc. and Gregory E. Evans effective December 19, 2008 (incorporated herein by reference to Exhibit 10.4 to the Company s Current Report on Form 8-K filed on December 23, 2008).
* 10.29	Amendment to the Employment Agreement between Carrizo Oil & Gas, Inc. and Richard H. Smith effective December 19, 2008 (incorporated herein by reference to Exhibit 10.5 to the Company s Current Report on Form 8-K filed on December 23, 2008).
* 10.30	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).
* 10.31	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 19, 2005).
* 10.32	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 19, 2005).
* 10.33	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 19, 2005).
* 10.34	Form of Employee Restricted Stock Award under the Incentive Plan of Carrizo Oil & Gas, Inc. (incorporated herein by reference to Exhibit 10.6 to the Company s Current Report on Form 8-K filed on January 27, 2006).
* 10.35	Form of Employee Restricted Stock Award Agreement (incorporated herein by reference to Exhibit 10.1 to the Company s Quarterly Report on Form 10-Q for the quarter ended September 30, 2006).
* 10.36	Form of Employee Stock Option Award Agreement (incorporated herein by reference to Exhibit 10.2 to the Company s Quarterly Report on Form 10-Q for the quarter ended September 30, 2006).
* 10.37	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).
* 10.38	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).
10.39	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)).
10.40	

	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)).
10.41	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
10.42	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).
10.43	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).
10.44	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).
10.45	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).
10.46	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).
10.47	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).
10.48	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).
10.49	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).
10.50	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).
10.51	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).

10.52	Base Salaries for certain Executive Officers.
21.1	Subsidiaries of the Company.
23.1	Consent of Pannell Kerr Forster of Texas, P.C.
23.2	Consent of Ryder Scott Company Petroleum Engineers.
23.3	Consent of Fairchild & Wells, Inc.

Exhibit Number	Description
23.4	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 of Ryder Scott Company Petroleum Engineers as of December 31, 2008.
99.2	Summary of Reserve Report of Fairchild & Wells, Inc. as of December 31, 2008.
99.3	Summary of Reserve Report of LaRoche Petroleum Consultants, Ltd. as of December 31, 2008.

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 of
Carrizo Oil & Gas, Inc.

We have audited the accompanying consolidated balance sheets of Carrizo Oil & Gas, Inc. as of December 31, 2008 and 2007 and the related consolidated statements of operations, shareholders equity and cash flows for each of the three years in the period ended December 31, 2008. Our audits also included the financial statement schedule included on page 61. 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 2007 and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2008, in conformity with U.S. generally accepted accounting principles.

We have also 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, 2008, based on criteria established in *Internal Control Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission, and our report dated March 12, 2009 expressed an unqualified opinion on the Company s internal control over financial reporting.

/s/ Pannell Kerr Forster of Texas, P.C.
Houston, Texas
March 12, 2009

REPORT OF INDEPENENT REGISTERED PUBLIC ACCOUNTING FIRMS

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

We have audited the internal control over financial reporting of Carrizo Oil & Gas, Inc. (the Company) as of December 31, 2008, based on criteria established in *Internal Control Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission. The Company s management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting, included in the accompanying *Management s Report on Internal Control Over Financial Reporting.* Our responsibility is to express an opinion on the Company s internal control over financial reporting based on our audit.

We conducted our audit in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether effective internal control over financial reporting was maintained in all material respects. Our audit included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, testing and evaluating the design and operating effectiveness of internal control based on the assessed risk, and performing such other procedures as we considered necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinion.

A company s internal control over financial reporting is a process designed by, or under the supervision of, the company s principal executive and principal financial officers, or persons performing similar functions, and effected by the company s board of directors, management, and other personnel to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with U.S. 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 U.S. 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 the inherent limitations of internal control over financial reporting, including the possibility of collusion or improper management override of controls, material misstatements due to error or fraud may not be prevented or detected on a timely basis. Also, projections of any evaluation of the effectiveness of the internal control over financial reporting to future periods are subject to the risk that the controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

In our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2008, based on the criteria established in *Internal Control Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission.

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the consolidated financial statements and financial statement schedule included on page 61 as of and for the year ended December 31, 2008 of the Company and our report dated March 12, 2009 expressed an unqualified opinion on those financial statements and financial statement schedule.

/s/ Pannell Kerr Forster of Texas, P.C.
Houston, Texas
March 12, 2009

CARRIZO OIL & GAS, INC.
CONSOLIDATED BALANCE SHEETS

	December 31, 2008	December 31, 2007
	(In thousands, except per share amount)	
ASSETS		
CURRENT ASSETS:		
Cash and cash equivalents	$ 5,184	$ 8,026
Accounts receivable, trade (net of allowance for doubtful accounts of $1,264 and $1,430 at December 31, 2008 and 2007, respectively)	24,675	27,114
Advances to operators	336	1,113
Fair value of derivative financial instruments	22,791	1,126
Prepayments and deposits	3,335	3,913
Deferred tax asset		324
Total current assets	56,321	41,616
PROPERTY AND EQUIPMENT, net full-cost method of accounting for oil and natural gas properties (including unevaluated costs of properties of $276,138 and $124,373 at December 31, 2008 and 2007, respectively)	1,021,621	646,810
DEFERRED FINANCING COSTS, NET	9,750	5,921
INVESTMENTS	3,274	11,071
FAIR VALUE OF DERIVATIVE FINANCIAL INSTRUMENTS	15,876	
OTHER ASSETS	1,172	3,245
TOTAL ASSETS	$ 1,108,014	$ 708,663
LIABILITIES AND SHAREHOLDERS EQUITY		
CURRENT LIABILITIES:		
Accounts payable, trade	$ 46,683	$ 49,700
Accrued liabilities	54,149	36,091
Advances for joint operations	3,815	872
Current maturities of long-term debt	173	2,251
Fair value of derivative financial instruments		2,755
Deferred tax liability	9,103	
Total current liabilities	113,923	91,669
LONG-TERM DEBT, net of current maturities	533,057	252,250
ASSET RETIREMENT OBLIGATION	6,503	5,869
FAIR VALUE OF DERIVATIVE FINANCIAL INSTRUMENTS		1,050
DEFERRED INCOME TAXES	26,920	46,321
DEFERRED CREDITS	625	783

COMMITMENTS AND CONTINGENCIES				
SHAREHOLDERS EQUITY:				
Common stock, par value $0.01 (90,000 shares authorized with 30,860 and 28,009 issued and outstanding at December 31, 2008 and 2007, respectively)		309		280
Additional paid in capital		380,571		239,672
Retained earnings		47,405		65,344
Accumulated other comprehensive income (loss), net of tax		(1,299)		5,425
Total shareholders equity		426,986		310,721
TOTAL LIABILITIES AND SHAREHOLDERS EQUITY	$	1,108,014	$	708,663

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

CARRIZO OIL & GAS, INC.
CONSOLIDATED STATEMENTS OF OPERATIONS

	For the Years Ended December 31, 2008	2007	2006
	(In thousands, except per share amounts)		
OIL AND NATURAL GAS REVENUES	$ 216,677	$ 125,789	$ 82,945
COSTS AND EXPENSES:			
Oil and natural gas operating expenses (exclusive of depletion, depreciation and amortization, shown separately below)	37,885	24,662	16,428
Third party gas purchases	6,570		
Depreciation, depletion and amortization	58,311	41,899	31,129
Impairment of oil and natural gas properties	138,591		
General and administrative	23,425	18,912	14,909
Accretion expenses related to asset retirement obligation	154	374	496
Total costs and expenses	264,936	85,847	62,962
OPERATING INCOME (LOSS)	(48,259)	39,942	19,983
OTHER INCOME AND EXPENSES:			
Gain (loss) on derivatives, net	37,499	(1,366)	16,457
Loss on extinguishment of debt	(5,689)		(294)
Equity in income of Pinnacle Gas Resources, Inc.			35
Interest income	269	691	969
Interest expense	(23,546)	(26,403)	(19,071)
Capitalized interest	15,641	11,718	9,975
Other income, net	17	130	427
INCOME (LOSS) BEFORE INCOME TAX EXPENSE	(24,068)	24,712	28,481
INCOME TAX EXPENSE (BENEFIT)	(6,129)	9,243	10,233
NET INCOME (LOSS)	$ (17,939)	$ 15,469	$ 18,248
OTHER COMPREHENSIVE INCOME (LOSS):			
Increase (decrease) in market value of investment in Pinnacle Gas Resources, Inc., net of taxes	(6,724)	5,425	
COMPREHENSIVE INCOME (LOSS)	$ (24,663)	$ 20,894	$ 18,248
BASIC EARNINGS (LOSS) PER COMMON SHARE	$ (0.60)	$ 0.59	$ 0.74

DILUTED EARNINGS (LOSS) PER COMMON SHARE	$ (0.60)	$ 0.57	$ 0.71
WEIGHTED AVERAGE SHARES OUTSTANDING:			
BASIC	30,010	26,287	24,827
DILUTED	30,010	27,120	25,565

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

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

	Common Stock	
	Shares	**Amount**
	(Dollars in thousands)	
BALANCE, January 1, 2006	24,251,430	$ 243
Common stock issued, net of offering cost	1,350,000	13
Common stock issued for property	2,000	
Stock options exercised for cash	101,800	1
Stock-based compensation		
Capitalization of repriced stock options of adoption of SFAS 123(R)		
Restricted stock awards, net of forfeitures	277,436	3
Common stock repurchased for tax withholding obligations	(2,061)	
Net income		
BALANCE, December 31, 2006	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 for tax withholding obligations	(7,440)	
Other comprehensive income		
Fair value adjustment to investment in Pinnacle Gas Resources, Inc., net of tax		
Net income		
Total other comprehensive income		
BALANCE, December 31, 2007	28,009,152	$ 280
Common stock issued, net of offering cost	2,587,500	26
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 tax		
Net loss		
Total other comprehensive loss		
BALANCE, December 31, 2008	30,859,647	$ 309

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

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

	Additional Paid in Capital	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Shareholders Equity
	(Dollars in thousands)			
BALANCE, January 1, 2006	$ 123,515	$ 31,627	$	$ 155,385
Common stock issued, net of offering cost	33,403			33,416
Common stock issued for property	55			55
Stock options exercised for cash	601			602
Stock-based compensation	3,007			3,007
Capitalization of repriced stock options at adoption of SFAS 123(R)	1,696			1,696
Restricted stock awards, net of forfeitures	(80)			(77)
Common stock repurchased to settle tax withholding obligations	(58)			(58)
Net income		18,248		18,248
BALANCE, December 31, 2006	$ 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 tax			5,425	5,425
Net income		15,469		15,469
Total other 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
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 income				

Fair value adjustment to investment in Pinnacle Gas Resources, Inc., net of tax				(6,724)	(6,724)
Net loss		(17,939)			(17,939)
Total other comprehensive loss					(24,663)
BALANCE, December 31, 2008	$ 380,571	$ 47,405	$	(1,299)	$ 426,986

CARRIZO OIL & GAS, INC.
CONSOLIDATED STATEMENTS OF CASH FLOWS

	For the Years Ended December 31,		
	2008	**2007**	**2006**
	(In thousands)		
CASH FLOWS FROM OPERATING ACTIVITIES:			
Net Income (Loss)	$ (17,939)	$ 15,469	$ 18,248
Adjustments to reconcile net income (loss) to net cash provided by operating activities			
Depreciation, depletion and amortization	58,311	41,899	31,129
Impairment of oil and natural gas properties	138,591		
Fair value (gain) loss on derivative financial instruments	(41,345)	7,377	(8,069)
Provision for allowance for doubtful accounts	(166)	(209)	1,386
Accretion of discounts on asset retirement obligations and debt	154	374	496
Loss on extinguishment of debt	4,601		294
Stock-based compensation	5,952	4,907	2,930
Equity in income of Pinnacle Gas Resources, Inc.			(35)
Deferred income taxes	(6,324)	8,329	9,829
Other	5,272	1,623	1,237
Changes in operating assets and liabilities			
Accounts receivable	2,605	316	(2,178)
Other assets	(3,661)	(210)	2,037
Accounts payable	(1,476)	15,463	5,560
Accrued liabilities	4,179	(107)	2,573
Net cash provided by operating activities	148,754	95,231	65,437
CASH FLOWS FROM INVESTING ACTIVITIES:			
Capital expenditures	(571,291)	(247,003)	(201,773)
Change in capital expenditure accrual	11,808	17,079	7,791
Proceeds from the sale of oil and natural gas properties	3,259	1,505	38,319
Advances to operators	776	994	(517)
Advances for joint operations	2,943	(229)	(4,786)
Other	(2,840)	(70)	(610)
Net cash used in investing activities	(555,345)	(227,724)	(161,576)
CASH FLOWS FROM FINANCING ACTIVITIES:			
Net proceeds from common stock issuances:			
Private placements, net of offering costs	135,075	71,926	33,525
Stock option exercises	262	1,031	602
Net proceeds from debt issuance and borrowings	778,182	174,000	80,000
Debt repayments	(498,923)	(108,258)	(40,536)
Deferred loan costs and other	(10,847)	(3,588)	(769)

Net cash provided by financing activities		403,749		135,111		72,822
NET INCREASE (DECREASE) IN CASH AND CASH EQUIVALENTS		(2,842)		2,618		(23,317)
CASH AND CASH EQUIVALENTS, beginning of year		8,026		5,408		28,725
CASH AND CASH EQUIVALENTS, end of year	$	5,184	$	8,026	$	5,408
SUPPLEMENTAL CASH FLOW DISCLOSURES:						
Cash paid for interest (net of amounts capitalized)	$	4,160	$	12,217	$	7,211
Cash paid for income taxes	$	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. Our current operations are principally focused in proven, producing natural gas plays known as shale plays or resource plays . The Company s 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 its wholly-owned subsidiary Carrizo (Marcellus) LLC, the Company is also actively seeking to establish a core area in another emerging resource play, the Marcellus Shale play in Pennsylvania, New York, West Virginia and Virginia. In addition to the Barnett and the Marcellus, we are active in other shale plays, including the Fayetteville in Arkansas, Barnett/Woodford in West Texas/New Mexico, Floyd/Neal in Mississippi, and the New Albany in Kentucky/Illinois. We also explore for, develop and produce natural gas and oil from traditional geologic trends along the onshore Gulf Coast area in Texas, Louisiana and Alabama, primarily in the Miocene, Wilcox, Frio and Vicksburg trends. 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

Prior to April 2006, the Company s investment in Pinnacle Gas Resources, Inc. (Pinnacle) was recorded using the equity method of accounting and was adjusted for the Company s equity in the subsidiary s profit or loss. In April 2006, the Company changed its accounting for Pinnacle to the cost method of accounting and adjusts the carrying amount of its investment for contributions to and distributions from the subsidiary.

In 2007, Pinnacle became a publicly traded entity on the Nasdaq Global Market. For accounting purposes, the Pinnacle common stock now has a readily determinable fair market value. The Company classifies the investment as available-for-sale and adjusts the book value to fair market value through other comprehensive income, net of taxes. This fair value adjustment is assessed quarterly for other than temporary impairment based upon publicly available information. If the loss is deemed other than temporary, it will be recognized in earnings.

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 periods financial statements to conform to the current presentation. These reclassifications had no effect on total assets, total liabilities, shareholders equity or net income.

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 undeveloped properties, future income taxes 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 effected 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 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.

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 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 oil and natural gas properties. The Company capitalized compensation costs and other costs of employees working directly on exploration activities of $7.8 million, $4.5 million and $3.5 million in 2008, 2007 and 2006, respectively. Maintenance and repairs are expensed as incurred.

Depreciation, depletion and amortization (DD&A) of proved oil and natural gas properties are based on the unit-of-production method using estimates of proved reserve quantities. Investments in unproved properties are not subject to DD&A until proved reserves associated with the projects can be determined or until they are impaired. Unevaluated properties 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. The depletable base includes estimated future development costs and, where significant, dismantlement, restoration and abandonment costs, net of estimated salvage values. The depletion rate per Mcfe for 2008, 2007 and 2006 was $2.23, $2.36 and $2.61, 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 would significantly alter the relationship between capitalized costs and proved reserves.

The net capitalized costs are limited to a ceiling test based on the estimated future net revenues from proved reserves, discounted at a 10% rate per annum, based on current economic and operating conditions (full cost ceiling). If net capitalized costs exceed this limit, the excess is charged to earnings. During 2008, the Company recorded an impairment of $138.6 million associated with its year end 2008 ceiling test analysis.

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

Oil and Natural Gas Reserve Estimates

The process of estimating quantities of proved reserves is inherently uncertain, and the reserve data included in this document are estimates prepared by Ryder Scott Company Petroleum Engineers, Fairchild & Wells, Inc. and LaRoche Petroleum Consultants, Ltd., 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 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 SEC 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 the Company s estimates. 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 the Company s estimated proved reserves. In accordance with SEC requirements, the Company based the estimated discounted future net cash flows from proved reserves on market prices and costs on the date of the estimate.

The Company s rate of recording depreciation, depletion and amortization expense for proved properties is dependent on the Company s estimate of proved reserves. If these reserve estimates decline, the rate at which the Company records these expenses will increase.

The Company s full cost ceiling test also depends on the Company s estimate of proved reserves. If these reserve estimates decline, the Company may be subjected to a full cost ceiling write-down. The Company recorded a full cost ceiling test write-down in 2008.

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.

Financing Costs, net

Net long-term debt financing costs of $9.8 million (net of $10.6 million accumulated amortization) and $5.9 million (net of $4.0 million accumulated amortization) were capitalized as of December 31, 2008 and 2007, 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 Secured Revolving Credit Facility.

Supplemental Cash Flow Information

The Statement of Cash Flows for the year ended December 31, 2008 does not include the adjustment of the investment in Pinnacle of $(6.7) million, net of tax. The Statement of Cash Flows for the year ended December 31, 2007 does not include the adjustment of the investment in Pinnacle of $5.4 million, net of tax. The Statement of Cash Flows for the year ended December 31, 2006 does not include the acquisition of $55,000 of oil and gas properties in exchange for the Company s common stock and the capitalization of stock-based compensation associated with the adoption of SFAS 123(R) of $1.7 million, 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

In June of 1997, the Company established the Incentive Plan of Carrizo Oil & Gas, Inc. (the Incentive Plan), which authorizes the granting of stock options and stock awards to directors, employees and independent contractors. The Company recognized the following stock-based compensation expenses for the years ended December 31:

	2008	2007	2006
		(In millions)	
Stock Option	$ 0.1	$ 0.3	$ 0.5
Restricted Stock	5.9	4.6	2.4
Total Stock-Based Compensation	$ 6.0	$ 4.9	$ 2.9

Stock Options. Effective January 1, 2006, the Company adopted Statement of Financial Accounting Standards (SFAS) No. 123 (revised 2004), *Share-Based Payment* (SFAS No. 123(R)), which requires companies to measure all stock-based compensation awards using the fair value method and record such expense in the financial statements over the vesting period of the options, which is generally three years. The Company implemented SFAS No. 123(R) using the modified prospective transition method.

The Company recognizes compensation expense for all unvested options outstanding as of January 1, 2006, options issued after January 1, 2006, and those options that are subsequently modified, repurchased or cancelled. The compensation expense is based on the grant-date fair value of the options and expensed over the vesting period.

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

The risk-free interest rate is based on the five-year Treasury bond at date of grant.

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

The market price volatility of the Company s common stock is based on daily, historical prices for the last three years.

The term of the grants is based on the simplified method as described in Staff Accounting Bulletin No. 107.

In addition, the Company estimates a forfeiture rate at the inception of the option grant based on historical data and adjusts this prospectively as new information regarding forfeitures becomes available.

Restricted Stock. The Company grants shares of restricted stock and measures deferred compensation based on the 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 as prescribed in SFAS 123(R). Restricted stock issued to other than employees 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 until vested.

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 increases an NOL carryforward, SFAS 123(R) prescribes that no windfall should be recognized until the deduction reduces income tax payable. At December 31, 2008, the Company had an NOL of approximately $67.5 million. The Company has postponed the recognition of approximately $5.7 million in windfall tax benefits associated with its stock-based compensation until a tax cash savings is realized.

Derivative Instruments

The Company uses derivatives 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 that was terminated 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 during the years ended December 31, 2008, 2007 and 2006 were treated as non-designated derivatives and the unrealized gain/(loss) related to the change in mark-to-market valuation was included in the Company s earnings.

The Company typically uses fixed-rate swaps, costless collars and basis differential swaps to hedge its exposure to material changes in the price of oil and natural gas and variable interest rates on long-term debt.

The Company s Board of Directors sets all risk management policies and reviews volumes, 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

Under SFAS No. 109 *Accounting for 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 assess the realizability of its deferred tax assets and considers future taxable income 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 under accounting standards, it is reduced by a valuation allowance. However, despite the Company s attempt to make an accurate estimate, the ultimate utilization of the deferred tax assets is highly dependent upon actual production and the realization of taxable income in future periods.

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, 2008, approximately 69% of the Company s open natural gas hedges were with Credit Suisse, and the remaining 31% were with Shell Energy North America (US), L.P. The open oil hedge positions were all arranged with Credit Suisse. 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.

During the fourth quarter of 2006, Reichmann Petroleum filed for bankruptcy. At the time, the Company had outstanding receivable balances of approximately $1.5 million for October 2006 production and advances to Reichmann for the drilling of wells in which Reichmann was the operator. The Company expects to recover approximately five percent of the receivable balance due at the time of bankruptcy. Accordingly, the Company increased the allowance by approximately $1.5 million during the fourth quarter of 2006. During 2007, the Company collected the receivable associated with October 2006 production and reduced the reserve for the Reichmann bankruptcy to $0.9 million.

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,		
	2008	**2007**	**2006**
DTE Energy Trading, Inc.	39%		
Cokinos Natural Gas Company	11%	11%	
Crosstex Energy	10%	15%	
Houston Pipeline Company		11%	
Energy Transfer		10%	
Reichmann Petroleum			10%
Chevron/Texaco			11%

Earnings Per Share

Supplemental earnings per share information is provided below:

	Year Ended December 31,		
	2008	**2007**	**2006**
	(In thousands, except per share amounts)		
Net income (loss) available to common shareholders	$ (17,939)	$ 15,469	$ 18,248
Basic weighted average common shares outstanding	30,010	26,287	24,827
Restricted stock		354	254
Stock options		479	484
Diluted weighted average shares outstanding	30,010	27,120	25,565
Earnings (loss) per share			
Basic	$ (0.60)	$ 0.59	$ 0.74

Diluted	$ (0.60)	$ 0.57	$ 0.71

Basic earnings per common share is based on the weighted average number of shares of common stock outstanding during the periods. Diluted earnings 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 341,698 shares of restricted stock/restricted stock units and 685,854 stock options at December 31, 2008 that were antidilutive due to the net loss for 2008. Shares subject to potential issuance upon conversion of the Convertible Senior Notes did not have any impact on the calculation for 2008. The Company had 2,500 stock options at December 31, 2006 that were antidilutive as the exercise price of the options was greater than the then current market price of the Company s stock.

Contingencies

Liabilities and other contingencies are recognized upon determination of an exposure, which when analyzed indicates that 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

In June 2001, the Financial Accounting Standards Board (FASB) issued SFAS No. 143, *Accounting for Asset Retirement Obligations* (SFAS No. 143). SFAS No. 143 requires that an asset retirement obligation (ARO) associated with the retirement of a tangible long-lived asset be recognized 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.

In accordance with the provisions of SFAS No. 143, the Company records an abandonment liability associated with its oil and natural gas wells when those assets are placed in service. Under SFAS No. 143, depletion expense is reduced since a discounted ARO is depleted in the property balance rather than the undiscounted value previously depleted under the old rules. The lower depletion expense under SFAS No. 143 is offset, however, by accretion expense, which is recognized over time as the discounted liability is accreted to its expected settlement value.

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.

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

	2008	**2007**
	(In thousands)	
Asset retirement obligation at beginning of year	$ 5,869	$ 3,625
Liabilities incurred	1,004	1,251
Liabilities settled	(177)	(234)
Accretion expense	154	374
Revisions to previous estimates	(347)	853
Asset retirement obligation at end of year	$ 6,503	$ 5,869

Foreign Currency

The company has foreign activities related to its operations in the U.K. North Sea. Accordingly, assets and liabilities related to these operations are translated into United States dollars at exchange rates in effect at the balance sheet date. Income and expense items are translated at average exchange rates throughout the year. Translation adjustments are charged or credited to other comprehensive income (loss) and are recorded net of applicable taxes. 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 charged to earnings.

Recently Issued Accounting Pronouncements

In March 2008, the FASB issued SFAS No. 161, *Disclosures about Derivative Instruments and Hedging Activities* (SFAS No. 161). This standard is intended to improve financial reporting by requiring 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 under SFAS No. 133, and how derivative instruments and related hedged items affect an entity s financial position, financial performance and cash flows. The provisions of SFAS No. 161 are effective for financial statements issued for fiscal years and interim periods beginning after November 15, 2008. The Company does not believe the adoption of SFAS No. 161 will have a significant effect on its consolidated financial position, results of operations or cash flows.

In May 2008, the FASB issued FASB Staff Position (FSP) Accounting Principles Board (APB) 14-1, *Accounting for Convertible Debt Instruments That May Be Settled in Cash upon Conversion* (*Including Partial Cash Settlement*). This FSP clarifies that convertible debt instruments that may be settled in cash upon conversion, including partial cash settlement, are not addressed by paragraph 12 of APB Opinion No. 14, *Accounting for Convertible Debt and Debt Issued with Stock Purchase Warrants*. Additionally, this FSP specifies that issuers of such instruments should separately account for the liability and equity components in a manner that will reflect the entity s nonconvertible debt borrowing rate when interest cost is recognized in subsequent periods. This FSP is effective for financial statements issued for fiscal years beginning after December 15, 2008 and early adoption is not permitted. The Company currently expects to value the 4.375% Senior Convertible Notes due 2028 as $309.6 million of debt and $64.2 million of equity representing the fair value of the conversion premium. Our effective interest rate is expected to be approximately 8%. After implementation of this standard, the FSP requires retrospective application which is expected to increase the Company s 2008 interest expense by approximately $6 million and increase the Company s future interest expense by approximately $12 million annually through May 2013 before consideration of any amounts that may be capitalized.

In June 2008, the FASB issued FSP Emerging Issues Task Force (EITF) 03-6-1, *Determining Whether Instruments Granted in Share-Based Payment Transactions Are Participating Securities*. This FSP provides that unvested share-based payment awards that contain nonforfeitable 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. The Company does not currently expect a material impact to its consolidated financial statements and disclosures upon adoption.

On December 31, 2008, the Securities and Exchange Commission (SEC) adopted a major revision to its rules governing oil and gas company reporting requirements. These include provisions that permit the use of new technologies to determine proved reserves and that allow companies to disclose their probable and possible reserves to investors. The current rules limit disclosure to only proved reserves. The new disclosure requirements also require companies to report the independence and qualification of the person primarily responsible for the preparation or audit of reserve estimates, and to file reports when a third party is relied upon to prepare or audit reserves estimates. The new rules also require that the net present value of oil and gas reserves to be reported and used in the full-cost ceiling test calculation should be based upon an average price for the prior 12-month period. The new oil and gas reporting requirements are effective for annual reports on Form 10-K for fiscal years ending on or after December 31, 2009, with early adoption not permitted. The Company is in the process of assessing the impact of these new requirements on its financial position, results of operations and financial disclosures.

Recently Adopted Accounting Pronouncements

We adopted the Financial Accounting Standards Statement No. 157, *Fair Value Measurement* (SFAS No. 157), effective January 1, 2008. SFAS No. 157 provides a framework for measuring fair value and enhances related disclosures. The implementation of SFAS No. 157 did not change our current valuation method and did not have a material effect on our consolidated financial position or results in operations. We included additional disclosures in the Notes to Consolidated Financial Statements with respect to the measurement of our assets and liabilities at fair value on the balance sheet date.

3. INVESTMENTS

Investments consisted of the following at December 31, 2008 and 2007:

	December 31, 2008	**December 31, 2007**
	(In thousands)	
Pinnacle Gas Resources, Inc.	$ 751	$ 11,071
Oxane Materials, Inc.	2,523	
	$ 3,274	$ 11,071

Pinnacle Gas Resources, Inc.

In 2003, the Company s wholly-owned subsidiary CCBM, Inc. (CCBM) contributed its 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).

The Company classifies the Pinnacle investment as available-for-sale and adjusts the investment to fair value through Other Comprehensive Income. At December 31, 2008, 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, 2008), which is approximately $2.0 million below original cost. The fair value of this investment based on quoted market prices, was in excess of or equal to the original cost in October 2008. Management believes that this recent decrease in value that commenced in October of 2008 is temporary.

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. As of December 31, 2008, the Company owned 2,422,238 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. The Company accounts for the investment using the cost method.

4. PROPERTY AND EQUIPMENT

At December 31, 2008 and 2007, property and equipment consisted of the following:

	December 31,	
	2008	**2007**
	(In thousands)	
Proved oil and natural gas properties	$ 958,726	$ 701,521
Unproved oil and natural gas properties	276,138	124,373
Land, building and other equipment	6,363	2,853
Total property and equipment	1,241,227	828,747
Accumulated depreciation, depletion and amortization	(219,606)	(181,937)
Property and equipment, net	$ 1,021,621	$ 646,810

Oil and natural gas properties not subject to amortization consist of the cost of unevaluated leaseholds, seismic costs associated with specific unevaluated properties, exploratory wells in progress, and secondary recovery projects before the assignment of proved reserves. These unevaluated costs are reviewed periodically by management for impairment, with the impairment provision included in the cost of oil and natural gas properties subject to amortization. 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 recovery activities and available funds for exploration and development. The Company expects it will complete its evaluation of the properties representing the majority of these costs within the next two to five years.

The significant decline in oil and natural gas prices 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 a non-cash ceiling test write-down at the end of the fourth quarter of 2008 of $138.6 million ($90.1 million after tax).

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,		
	2008	**2007**	**2006**
		(In thousands)	
Provision at the statutory tax rate	$ (8,424)	$ 8,649	$ 9,968
Preferred dividend on Pinnacle			141

Increase in valuation allowance for equity in income of Pinnacle			(153)
State taxes	123	594	277
Nondeductible expenses	1,930		
Other	242		
Income tax expense (benefit)	$ (6,129)	$ 9,243	$ 10,233

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, 2008 and 2007, the tax effects of these temporary differences resulted principally from the following:

	December 31, 2008	December 31, 2007
	(In thousands)	
Deferred income tax assets:		
Net operating loss carryforward	$ 23,608	$ 17,430
Stock based compensation	1,549	1,675
Fair value derivative instruments		1,332
Allowance for doubtful accounts	442	500
Equity in income of Pinnacle	385	385
Valuation allowance	(385)	(385)
Adjustmennt to fair value of investment in Pinnacle	699	
	26,298	20,937
Deferred income tax liabilities:		
Oil and gas acquisition, exploration and development costs deducted for tax purposes in excess of financial statement DD&A	26,698	48,010
Capitalized interest	20,809	15,335
Adjustment to fair value of investment in Pinnacle		2,921
Fair value derivative instruments	14,659	668
Other	155	
	62,321	66,934
Net deferred income tax liability	$ 36,023	$ 45,997

At December 31, 2008 and 2007, the net deferred income tax liability is classified as follows:

	December 31, 2008	December 31, 2007
	(In thousands)	
Current deferred tax asset	$	$ (324)
Current deferred tax liability	9,103	
Deferred income taxes	26,920	46,321
Deferred income tax liability, net	$ 36,023	$ 45,997

The realization of deferred tax assets is dependent on the Company s ability to generate taxable earnings in the future. The Company believes it will generate 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 Pinnacle in future periods, which management believes is unlikely. The Company has a net operating loss carryforward totaling approximately $67.5 million, which is scheduled to expire over a period from 2019 through 2028.

On January 1, 2007, the Company adopted FASB Interpretation No. 48, *Accounting for Uncertainty in Income Taxes an interpretation of FASB Statement No. 109* (FIN 48). FIN 48 prescribes a measurement process for recording in the financial statements uncertain tax positions taken or expected to be taken in a tax return. Additionally, FIN 48 provides guidance regarding uncertain tax positions relating to derecognition, classification, interest and penalties, accounting in interim periods, disclosure and transition. The Company classifies interest and penalties associated with income taxes as interest expense. At December 31, 2008, the Company had no material uncertain tax positions and the tax years 2003 through 2007 remained open to review by federal and various state tax jurisdictions.

6. LONG-TERM DEBT

At December 31, 2008 and 2007, long-term debt consisted of the following:

	December 31, 2008	December 31, 2007
	(In thousands)	
Convertible Senior Notes	$ 373,750	$
Senior Secured Revolving Credit Facility	159,000	34,000
Second Lien Credit Facility		220,500
Other	480	1
	533,230	254,501
Less: current maturities	(173)	(2,251)
	$ 533,057	$ 252,250

Convertible Senior Notes

In May 2008, the Company issued $373.8 million aggregate principal amount of 4.375% convertible senior notes due 2028 (Convertible Senior Notes). Interest is payable on June 1 and December 1 each year, commencing December 1, 2008. 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 Carrizo s conversion obligation in excess of such principal amount. The notes are convertible into Carrizo 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 Carrizo 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 Carrizo 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 covenant 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 of the Company and rank equal to all future senior unsecured debt but rank second in priority to the Senior Secured Revolving Credit Facility.

Senior Secured Revolving Credit Facility

On May 25, 2006, the Company entered into a Senior Secured Revolving Credit Facility (Senior Credit Facility) with JPMorgan Chase Bank, National Association, as administrative agent. The Senior Credit Facility provided for a revolving credit facility up to the lesser of the borrowing base and $200.0 million. It is secured by substantially all of the Company s proved oil & gas assets and is guaranteed by the Company s subsidiaries, CCBM, Inc., CLLR, Inc., Carrizo (Marcellus) LLC and Carrizo Marcellus Holdings, Inc.

In the fourth quarter of 2008, the Company amended the Senior Credit Facility to (1) increase the borrowing base to $250.0 million; (2) extend the maturity date to October 29, 2012; (3) increase the maximum total net debt to Consolidated EBITDAX to 4.0 to 1.0; (4) change the semi-annual borrowing base redetermination dates to March 31 and September 30; (5) change the interest rate provisions; and (6) replace JPMorgan Chase Bank with Guaranty Bank as the administrative agent bank.

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 0.75% and 2.25% (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 2.0% to 3.5% (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 2.0% to 3.5% (depending on the then-current level of borrowing base usage). At December 31, 2008, the average interest rate for amounts outstanding under the Senior Credit Facility was 3.0%.

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 1.0 to 1.0; and (2) a maximum total net debt to Consolidated EBITDAX (as defined in the Senior Credit Facility) of 4.0 to 1.0. Although the Company currently believes that it can comply with all of the financial covenants with the business plan that it has put in place, 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 the Company receives 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, the Company may seek to further reduce its capital and exploration budget, sell non-strategic assets, opportunistically modify or increase its natural gas hedges or approach the lenders under our Senior Credit Facility for modifications of either or both of the financial covenants discussed above. There can be no assurance that the Company 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. 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, 2008, the Company was in compliance with all of our debt covenants.

At December 31, 2008, the Company had $159.0 million of borrowings outstanding under the Senior Credit Facility and the borrowing base availability was $91.0 million.

Second Lien Credit Facility

On July 21, 2005, the Company 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, the Company repaid in full the $219.9 million outstanding under the Second Lien Credit Facility and terminated the facility in connection with the issuance of its Convertible Senior Notes. The Company recorded a loss on extinguishment of approximately $5.7 million during 2008.

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, 2008, 2007 and 2006 was $0.9 million, $0.9 million and $0.6 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, 2008 are as follows (in thousands):

	Amount (in thousands)
2009	$ 32,575
2010	33,540
2011	15,929
2012	5,858
2013 and Thereafter	21,223
	$ 109,125

8. SHAREHOLDERS EQUITY AND STOCK INCENTIVE PLAN

Shareholders Equity

The following is a summary of changes in the Company s common stock shares for the years ended December 31,:

	2008	2007	2006
		(In thousands)	
Shares outstanding at January 1	28,009	25,981	24,251
Common stock issued	2,588	1,800	1,350
Restricted stock issued, net of forfeitures	203	112	278
Stock options exercised	65	124	102
Common stock issued for property			2
Common stock repurchased and retired for tax withholding obligation	(5)	(8)	(2)
Shares outstanding at December 31	30,860	28,009	25,981

In February 2008, the Company completed an underwritten public offering of 2,587,500 shares of its common stock at a price of $54.50 per share. The number of shares sold was approximately 9.2% of the Company s outstanding shares before the offering. The Company received proceeds of approximately $135.1 million, net of expenses, which were used to 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 number of shares sold was approximately 6.8% of the Company s fully diluted shares outstanding before the offering. The Company used substantially all of the net proceeds to fund in part its capital expenditure program, including its drilling and leasing programs in the Barnett Shale and appraisal well drilling in the North Sea. Pending those uses, the Company used a portion of the net proceeds of approximately $72.0 million to repay $54 million of outstanding borrowings under the Senior Credit Facility.

In July 2006, the Company sold 1.35 million shares of the Company s common stock to institutional investors at a price of $26.00 per share in a private placement. The number of shares sold was approximately 5.4% of the Company s fully diluted shares outstanding before the offering. The net proceeds, after deducting placement agents fees but before paying offering expenses, of approximately $33.7 million were principally used to fund a portion of the Company s 2006 capital expenditures program.

Stock Incentive Plan

In June 1997, the Company established the Incentive Plan of Carrizo Oil & Gas, Inc. (the Incentive Plan), which authorizes the granting of stock options and restricted stock awards to directors, employees and independent contractors. The Company may grant awards of up to 2,800,000 shares under the Incentive Plan and has granted options, restricted stock and restricted stock units covering 2,559,658 shares through December 31, 2008, net of forfeitures.

Stock Options. Prior to 2006, the Company issued stock options that become exercisable ratably over a three year period and expire ten years from the date of the grant. The table below summarizes stock option activity for the three years ended December 31, 2008:

	Shares	Weighted-Average Exercise Prices	Weighted-Average Remaining Life (In years)	Aggregate Intrinsic Value (In millions)
For the Year Ended December 31, 2006				
Outstanding, beginning of period	1,025,204	$ 5.53		
Granted				
Exercised	(101,800)	5.91		
Forfeited	(32,335)	12.63		
Outstanding, end of period	891,069	$ 5.25		
Exercisable, end of period	834,799	$ 4.65		
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	3.0	$ 7.0
Exercisable, end of period	685,854	$ 4.71	3.0	$ 7.0

At December 31, 2008, the Company had no unrecognized expense associated with nonvested stock option awards. The total intrinsic value (current market price less the option strike price) of options exercised during the years ended December 31, 2008, 2007 and 2006 was $2.5 million, $4.5 million and $2.5 million, respectively, and the Company received $0.3 million, $1.0 million and $0.6 million in cash in connection with these exercises for the years ended December 31, 2008, 2007 and 2006, respectively.

Restricted Stock Shares. 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 $7.8 million as of December 31, 2008 and will be amortized to expense over the next three years. The table below summarizes restricted stock activity for the three years ended December 31, 2008:

	Shares/ Units	Weighted-Average Price
Unvested restricted stock shares at December 31, 2005	87,585	$ 15.98
Granted	303,968	27.42
Vested	(38,812)	17.35
Forfeited	(26,532)	23.31
Unvested restricted stock shares 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 shares 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 shares at December 31, 2008	341,698	$ 34.93

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 Avista, a private equity fund. 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. 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). After the Initial Cash Contribution has been funded by Avista, the parties will share all costs of joint venture operations in accordance with their participating interests, which the Company expects will generally be 50/50. As a result of Avista s obligation to fund the Initial Cash Contribution, the Company does not currently expect that it will be required to contribute any cash to fund capital and exploration expenditures in the Marcellus Shale during 2009.

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. 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 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., Grey Wolf Inc., Hercules Offshore L.L.C., 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 and Brigham Exploration. 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, L.L.C. 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,		
	2008	**2007**	**2006**
		(In millions)	
Basic Energy Services	$0.4	$ 0.2	$ 0.5
Grey Wolf Drilling	7.1	6.8	6.7
Brigham Exploration[1]		(0.3)	(0.6) [2]
Quantum Geophysical Inc.			0.2
Hercules Offshore, L.L.C.	3.2		

(1) 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.

(2) Includes $1.2 million of net revenues related to wells operated by

Brigham Exploration and $0.6 million of net revenues related to wells operated by the Company.

It is management s opinion that the transactions with these entities were executed at prevailing market rates. At December 31, 2008 and 2007, the Company had an outstanding related-party net receivable balance of approximately $66,000 and net payable balance of approximately $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 for approximately $0.2 million. During 2008, the Company did not acquire any additional acreage from Black Stone. 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 $0.6 and $0.8 million in 2008 and 2007, respectively.

Due to the limited capital available at times to fund all of the Company s ongoing lease acquisition efforts in the Barnett Shale, Marcellus Shale, Fayetteville Shale and other plays, the Company elects from time to time to enter into various lease purchase option agreements with a number of third parties, including, in 2006, Steven A. Webster, the Company s Chairman of the Board. The lease purchase option arrangement with Mr. Webster expired at the end of 2006. The terms and conditions of the lease purchase option arrangement with Mr. Webster were consistent with the lease purchase option arrangements the Company entered into with unrelated third parties. These lease purchase option arrangements provide the Company the option to purchase leases from the counterparties, over an option period, generally 90 days, for the counterparties original cost of the leases plus an option fee. The Company paid Mr. Webster fees totaling approximately $250,000 in 2006. In accordance with the lease purchase option agreement, the Company also assigned to Mr. Webster an overriding royalty interest on any lease the Company acquired from Mr. Webster under the lease purchase option agreement with him, which overriding royalty interest varied from one-half to one percent of 8/8ths, proportionally reduced to the actual net interest in any given lease acquired from Mr. Webster. We paid Mr. Webster approximately $430 and $50 in 2008 and 2007, respectively, in overriding royalties under these arrangements.

See Note 3 for a discussion of the investment in Pinnacle.

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.

10. DERIVATIVE FINANCIAL INSTRUMENTS

The Company enters into swaps, options, collars and other derivative contracts to manage price risks 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 two 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 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 interest rate fluctuations on borrowings under the 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 net gain (loss) on derivatives in Other Income and Expenses in the Consolidated Statement of Operations. In addition, the Company records the realized gains (losses) associated with the cash settlements of these derivative instruments in the net gain (loss) on derivatives in Other Income and Expenses in the Consolidated Statement of Operations. For the years ended December 31, 2008, 2007 and 2006, the Company recorded the following related to its derivatives:

	Year Ended December 31, 2008	2007	2006
	(In millions)		
Realized gain (loss)			
Natural gas and oil derivatives	$ 0.6	$ 5.8	$ 6.8
Interest rate swaps	(1.2)	0.2	1.0
Gain (loss) on interest rate swap sell down	(3.3)		0.6
	(3.9)	6.0	8.4
Unrealized gain (loss)			
Natural gas and oil derivatives	38.6	(4.6)	8.7
Interest rate swaps	2.8	(2.8)	(0.6)
	41.4	(7.4)	8.1
Net Gain (Loss) on Derivatives	$ 37.5	$ (1.4)	$ 16.5

At December 31, 2008 the Company had the following outstanding derivative positions:

	Natural Gas Swaps		Natural Gas Collars			Basis Differential Swaps(2)	
Quarter	**MMbtu**	**Average Fixed Price(1)**	**MMBtu**	**Average Floor Price(1)**	**Average Ceiling Price(1)**	**MMBtu**	**Price**

First Quarter 2009	2,803,000	$ 6.13	2,520,000	$ 7.37	$ 9.10	310,000	$0.31
Second Quarter 2009	1,547,000	5.40	2,548,000	7.12	8.85		
Third Quarter 2009			2,576,000	7.16	8.88	920,000	0.31
Fourth Quarter 2009			2,576,000	7.17	8.90		
First Quarter 2010			1,620,000	7.92	9.63		
Second Quarter 2010			1,638,000	7.18	8.89		
Third Quarter 2010			1,656,000	7.35	9.06		
Fourth Quarter 2010			1,656,000	7.45	9.16		
First Quarter 2011			450,000	9.70	11.70		
Second Quarter 2011			455,000	8.25	10.25		
Third Quarter 2011			460,000	8.65	10.65		
Fourth Quarter 2011			460,000	8.85	10.85		
First Quarter 2012			455,000	9.55	11.55		
Second Quarter 2012			455,000	8.35	10.35		
TOTAL	4,350,000		19,525,000			1,230,000	

Quarter	Bbls	Oil Collars Average FloorPrice(3)	Average Ceiling Price(3)
First Quarter 2009	9,000	$131.65	$ 151.65
Second Quarter 2009	9,100	131.40	151.40
Third Quarter 2009	9,200	130.85	150.85
Fourth Quarter 2009	9,200	130.35	150.35
TOTAL	36,500		

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

(2) Basis differential swaps cover the price differential for natural gas between NYMEX and HSC.

(3) Based on West Texas intermediate index prices.

The fair value of the outstanding oil and natural gas derivatives at December 31, 2008 and 2007 was an asset of $38.7 million and $0.1 million, respectively.

At December 31, 2008, approximately 69% of the Company s open natural gas hedges were with Credit Suisse, and the remaining 31% were with Shell Energy North America (US), L.P. The open oil hedge positions were all arranged with Credit Suisse.

During the third quarter of 2005, the Company entered into interest rate swap agreements with respect to amounts outstanding under the Second Lien Credit Facility. These arrangements were designed to manage the Company s exposure to interest rate fluctuations during the period beginning January 1, 2006 through June 30, 2007 by effectively exchanging existing obligations to pay interest based on floating rates for obligations to pay interest based on fixed LIBO rates. In connection with an amendment to the Second Lien Credit Facility, the remaining open derivative positions on interest rate swaps were cash settled, resulting in a realized gain of $0.6 million on December 21, 2006.

During the first and second quarter of 2007, the Company entered into interest swap agreements covering amounts outstanding under the Second Lien Credit Facility. These arrangements were designed to manage the Company s exposure to interest rate fluctuations 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

Effective January 1, 2008, the Company adopted FASB Statement No. 157, *Fair Value Measurements* (SFAS No. 157), which defines fair value, establishes a framework for measuring fair value, establishes a fair value hierarchy based on the quality of inputs used to measure fair value and enhances disclosure requirements for fair value measurements. The implementation of SFAS No. 157 did not cause a change in the method of calculating fair value of assets or liabilities, with the exception of incorporating a measure of the Company s own nonperformance risk or that of its counterparties as appropriate, which was not material. The primary impact from adoption was additional disclosures.

The Company elected to implement SFAS No. 157 with the one-year deferral permitted by FASB Staff Position No. FAS 157-2, *Effective Date of FASB Statement No. 157,* issued February 2008, which defers the effective date of SFAS No. 157 for one year for certain nonfinancial assets and nonfinancial liabilities measured at fair value, except those that are recognized or disclosed at fair value in the financial statements on a recurring basis.

SFAS No. 157 establishes 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, 2008, 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.	$ 751	$	$	$ 751
Oil and natural gas derivatives		38,667		38,667
Total	$ 751	$ 38,667	$	$ 39,418

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.

Effective January 1, 2008 the Company adopted SFAS No. 159, *The Fair Value Option for Financial Assets and Financial Liabilities, including an amendment of SFAS No. 115* (SFAS No. 159). SFAS No. 159 allows companies to choose to measure financial instruments and other items at fair value that previously were not required to be measured at fair value. The Company elected not to present any financial instruments or other items at fair value that were not required to be presented at fair value prior to the adoption of SFAS No. 159.

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

The following disclosures provide unaudited information required by SFAS No. 69, *Disclosures About Oil and Gas Producing Activities.*

Costs Incurred

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

	Year Ended December 31,		
	2008	2007	2006
		(In thousands)	
Property acquisition costs			
Unproved	$ 271,618	$ 54,467	$ 48,409
Proved			
Exploration costs	235,382	144,402	104,473
Development costs	49,626	30,562	37,889
Asset retirement obligation	630	1,961	299
Total costs incurred[1]	$ 557,256	$ 231,392	$ 191,070

(1) Excludes capitalized interest on unproved

properties of $14.4 million, $11.7 million and $10.0 million for the years ended December 31, 2008, 2007 and 2006, respectively, and includes capitalized overhead of $7.8 million, $4.5 million and $3.5 million for the years ended December 31, 2008, 2007 and 2006, respectively.

Oil And Natural Gas Reserves

Proved reserves are estimated quantities of oil and natural gas which geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under existing economic and operating conditions. Proved developed reserves are proved reserves that can reasonably be expected to be recovered through existing wells with existing equipment and operating methods.

Proved oil and natural gas reserve quantities at December 31, 2008, 2007 and 2006, and the related discounted future net cash flows before income taxes are based on estimates prepared by Ryder Scott Company Petroleum Engineers, LaRoche Petroleum Consultants, Ltd., and Fairchild & Wells, Inc. 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,		
	2008	2007	2006
Proved developed and undeveloped reserves			
Beginning of year	248,433	166,798	103,058
Purchase of oil and natural gas properties in place			
Discoveries and extensions	146,189	131,836	91,090
Revisions	21,661	(34,017)	(11,026)
Sales of oil and gas properties in place		(142)	(6,148)
Production	(23,547)	(16,042)	(10,176)
End of year	392,736	248,433	166,798
Proved developed reserves at beginning of year	122,598	73,912	44,681
Proved developed reserves at end of year	216,229	122,598	73,912

	Thousands of Barrels of Oil, Condensate and Natural Gas Liquids at December 31,		
	2008	2007	2006
Proved developed and undeveloped reserves			
Beginning of year	16,531	7,195	7,925
Purchase of oil and natural gas properties in place		796	
Discoveries and extensions	2,088	3,536	359
Revisions	36	5,245	(823)
Sales of oil and gas properties in place			(11)
Production	(347)	(241)	(255)
End of year	18,308	16,531	7,195
Proved developed reserves at beginning of year	6,536	1,638	1,343
Proved developed reserves at end of year	7,869	6,536	1,638

During 2008, 2007 and 2006, the Company reported considerable discoveries and extensions to the Company s natural gas reserves primarily due to the Company s drilling program in the Barnett Shale play. 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. In 2008, the Company included a large natural gas revision primarily due to actual performance of wells in the Barnett Shale. In 2007, the Company reported a large natural gas revision largely attributable to the reclass of natural gas liquids, previously presented as natural gas equivalents, to the reserve category of oil and condensate. During 2007, the Company increased production of natural gas liquids as a result of an increase in processed gas sales. In prior years, any natural gas liquid production was deemed immaterial.

The Company reported significant downward revisions to its natural gas reserves in 2006 due to a decline in natural gas prices.

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,		
	2008	2007	2006
		(In thousands)	
Future cash inflows	$ 2,501,460	$ 2,663,281	$ 1,356,118
Future oil and natural gas operating expenses	868,027	618,479	350,076
Future development costs	315,837	277,070	193,245
Future income tax expenses	407,897	394,569	202,685
Future net cash flows	909,699	1,373,163	610,112
Less 10% annual discount for estimating timing of cash flows	468,445	710,793	311,401
Standard measure of discounted future net cash flows	$ 441,254	$ 662,370	$ 298,711

Future cash flows are computed by applying year-end prices of oil and natural gas to year-end quantities of proved oil and natural gas reserves. Average prices used in computing year end 2008, 2007 and 2006 future cash flows were $29.61, $74.45 and $54.73 for oil, respectively, and $4.99, $5.99 and $5.77 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.

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,		
	2008	2007	2006
		(In thousands)	
Changes due to current-year operations			
Sales of oil and natural gas, net of oil and natural gas operating expenses	$ (171,944)	$ (101,127)	$ (72,077)
Extensions and discoveries	228,037	340,503	139,657
Purchases of oil and gas properties		20,625	
Changes due to revisions in standardized variables			
Prices and operating expenses	(371,924)	142,126	(71,814)
Income taxes	22,307	(89,158)	16,422
Future development costs, net	11,052	57,126	64,166
Revision of quantities	44,643	(7,614)	(43,362)
Sales of reserves in place		(351)	(15,518)
Accretion of discount	83,931	38,718	40,423
Production rates, timing and other	(67,218)	(37,189)	(58,527)
Net change	(221,116)	363,659	(630)

Beginning of year	662,370	298,711	299,341
End of year	$ 441,254	$ 662,370	$ 298,711

Sales of oil and natural gas, net of oil and natural gas operating expenses, are based on historical pretax results. Sales of oil and natural gas properties, extensions and discoveries, purchases of minerals in place and the changes due to revisions in standardized variables are reported on a pretax discounted basis, while the accretion of discount is presented on a before tax basis.

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.

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	$ 80,010	(7,672)	103,422
Net income (loss)	$ (5,296)	$ (12,622)	$ 66,199	$ (66,220)
Basic net income (loss) per share	$ (0.18)	$ (0.42)	$ 2.18	$ (2.17)
Diluted net income (loss) per share	$ (0.18)	$ (0.42)	$ 2.14	$ (2.17)

2007	First	Second	Third	Fourth
	(In thousands, except per share amounts)			
Revenues	$ 22,612	$ 32,891	$ 30,305	$ 39,981
Costs and expenses, net	25,157	24,754	26,072	34,337
Net income (loss)	$ (2,545)	$ 8,137	$ 4,233	$ 5,644
Basic net income (loss) per share	$ (0.10)	$ 0.32	$ 0.16	$ 0.20
Diluted net income (loss) per share	$ (0.10)	$ 0.31	$ 0.16	$ 0.20

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 13, 2009

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 13, 2009
/s/ Paul F. Boling Paul F. Boling	Chief Financial Officer, Vice President, Secretary and Treasurer (Principal Financial Officer and Principal Accounting Officer)	March 13, 2009
/s/ Steven A. Webster Steven A. Webster	Chairman of the Board	March 13, 2009
/s/ Thomas L. Carter, Jr. Thomas L. Carter, Jr.	Director	March 13, 2009
/s/ Paul B. Loyd, Jr. Paul B. Loyd, Jr.	Director	March 13, 2009
/s/ F. Gardner Parker F. Gardner Parker	Director	March 13, 2009
/s/ Roger A. Ramsey Roger A. Ramsey	Director	March 13, 2009
/s/ Frank A. Wojtek Frank A. Wojtek	Director	March 13, 2009